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 #19-4
October 16, 2019 10:00 a.m. – 4:00 p.m. EST
October 17, 2019 8:30 a.m. – 2:00 p.m. EST
Power Vista Visitor Center
Community Room
5777 Lewiston Road
Lewiston, New York
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada)

Day 1 - RSC Business:
Guest Code: 648639751
Password: wSJuu*32 (97588032 from phones)

Day 2 - DER Forum:
Guest Code: 640262700
Password: 85MpXNF? (85679630 from phones)

Day One RSC Business:

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated May 13, 2019
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 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 ERO Reliability Risk Priorities Report
5.3 NAGF Battery and Energy Storage Workshop
5.4 RSC Scope of Work

5.5 RSC Work Plan

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
Project 2017-01 Modifications to BAL-003-1.1 David Lemmons Chair of DT @ 1:15PM	4/17/19 (F)	1/17/19 (I)
Project 2015-09 Establish and Communicate System Operating Limits Dean Laforest Chair of DT @ 1:00PM	10/17/18 (F)	10/17/18 (I)
Project 2016-02 Modifications to CIP Standards Norm Dang of DT in person	9/26/19 (F)	7/17/19 (A)
Project 2018-04 Modifications to PRC-024-2 Developer not available	11/4/19 (F)	11/4/19 (A)
Project 2019-01 Modifications to TPL-007-3 Per-Anders Lof of DT @ 1:45PM	9/9/19 (F)	9/9/19 (I)
Project 2019-02 BES Cyber System Information Access Management Developer not available	4/26/19 (F)	
Project 2019-03 Cyber Security Supply Chain Risks	8/1/19 (I)	
Project 2019-04 Modifications to PRC-005-6 Developer not available	8/28/19 (F)	
Project 2019-05 Modifications to PER-003-2	8/30/19 (I)	
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final		

6.2 Ballot History (Since last RSC Meeting)

6.3 Comment Form History (Since last RSC Meeting)

7.0 NERC Drafting Team Nominations

7.1 Currently Posted Drafting Team Vacancies

7.1.1 None at this time

7.2 Closed Drafting Team Nominations (Since last RSC Meeting)

7.2.1 None at this time

7.3 Solicitation for Informal Development Teams

7.3.1 None at this time

8.0 NPCC Regional Reliability Standards

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

8.1 Current Activities:

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

9.0 NPCC Non-Standards
https://www.npcc.org/Standards/SitePages/NonStandardsList.aspx

9.1 Items for Discussion:
- 9.1.1 Directory#7 *SPS* and NPCC Glossary term SPS
  (Status of RAS Implementation/Transition)
- 9.1.2 A-10 Classification of BPS Elements (status of TFCP review).
- 9.1.3 Directory Manual --- Cost Effective Revisions
  RSC Review of Open Process Comments. (Posting Closed 10-11-2019)
- 9.1.4 BOD Approved Corporate Goal:
  (Cost Effective Pilot ---- Directory #4 and Directory#5)
- 9.1.5 Full Member Ballot Directory #5 and Directory #6

9.2 Items for Approval:
- 9.2.1 Directory Manual ----- RSC Approval
  RSC Approval of Cost-Effective Revisions

9.3 Executive Tracking Summary
- 9.3.1 C-33 Retirement

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 23rd – Call	February 20th – Call	March 20th – Austin TX (Austin Energy)
April 17th – Call	May 22nd – Call	June 26th – Atlanta GA (NERC)
July 24th – Call	August 21st – Call	September 18th – Kansas City MO (KCP&L)
October 23rd – Call	November 20th – Call	December 18th – Atlanta GA (NERC)

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

February 6-7 - Meeting	May 8-9 - Meeting	August 14-15 - Meeting
November 5-6 - Meeting		

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

13.0 NERC Items of Interest (Since last RSC Meeting)

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

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

13.2 Alerts

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

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

14.0 Other Items of Interest

14.1 NPCC Board of Directors Meeting (BOD) 2019

January 30th – ISO-NE Backup Control Center, Windsor CT	March 20th - Call	May 1st – NPCC Office
June 5th – Call	June 26th – NPCC Office	August 7th – Call
September 4th and 5th – Halifax, Nova Scotia	October 30th – Call	December 4th – Montreal, Quebec

14.2 NPCC and ERO 2020 Business Plan and Budget Schedule

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2019 Meeting Date

February 13th-14th, Eversource, Boston MA
May 15th-16th, Saratoga NY
August 7th-8th, Hydro One Toronto Canada
October 16th-17th, Lewiston NY
December 5th, 2019 Montreal Canada (General Meeting)

15.2 RSC 2020 Meeting Date

February 12th-13th, Eversource, Boston MA
May 13th-14th, Saratoga NY
August 5th-6th, Toronto/Montreal Canada
October 14th-15th, Lewiston NY
December 3rd (General Meeting)

Day Two DER Forum:

16.0 Distributed Energy Resources (DER) Forum Topics

16.1 DER, Approach to Regional Guidance and DER Impact Reporting
16.2 DER-BES impact analysis and TDcoSim by Jim Reilly (10:00AM-10:45AM)
16.3 NERC IRPTF activities by Rich Bauer (9:00AM-9:30AM)
16.4 DER presentation by Kelli Joseph from Clearway Energy (In Person)
16.5 National Grid's East Pulaski New York Battery Energy Storage System Presentation by Jim Dillon (10:45AM-11:30AM)
16.6 IEEE 1547 presentation by David Forrest (In Person)
16.7 DER presentation by Ted Ko from Stem (11:30AM-12:00PM)
16.8 DER presentation by Chris Larsen from Dynapower (In Person)

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.

Public Announcement

RSC and DER Forum Meetings, WebEx, and Conference calls:
Participants are reminded that this meeting, WebEx, and conference call are public. The access number was posted on the NPCC website and widely distributed. Speakers on the call should keep in mind that the listening audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

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 #19-3
August 7, 2019 10:00 a.m. – 4:00 p.m. EST
August 8, 2019 8:30 a.m. – 2:00 p.m. EST
Hydro One South Tower 06 Boardroom
483 Bay Street
Toronto, Ontario Canada
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada)

Day 1 - RSC Business:
Guest Code: 649523881
Password: Ev9bpE3* (38927330 from phones)

Day 2 - DER Forum:
Guest Code: 643668616
Password: UyVe2M5? (89832650 from phones)

Day One RSC Business:

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated May 13, 2019
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.	Kal Ayoub	FERC	Guest	1, 2	
5.	Al McMeekin	NERC	Guest	1, 2	
6.	Chantal Mazza	Hydro Quebec	2	1, 2	
7	Nicolas Compas	Hydro Quebec	Guest	2	Via Webex
8.	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	1, 2	Via Webex
9.	Chris Overberg	Consolidated Edison Co. of New York, Inc.	3	1, 2	Via Webex
10.	Qinling Zheng	Consolidated Edison Co. of New York, Inc.	5	1, 2	Via Webex
11.	Constantin Chitescu	Ontario Power Generation, Inc.	4	1, 2	

12.	Mike Cooke	Ontario Power Generation, Inc.	4	1, 2	
13.	David Lemstra	Ontario Power Generation, Inc.	Guest	1, 2	
14.	Chris Moir	Ontario Power Generation, Inc.	Guest	1, 2	
15.	Payam Farahbakhsh	Hydro One Networks	1	1, 2	
16.	Adnan Akhtar	Hydro One Networks	Guest	2	
17.	Ben Wu	Orange & Rockland Utilities, Inc.	3	1, 2	
18.	David Burke	Orange & Rockland Utilities, Inc.	3	1, 2	Via Webex
19.	Brian Robinson	Utility Services, Inc.	5	1, 2	
20.	Dan Kopin	Utility Services, Inc.	Guest	2	
21.	Sean Bodkin	Dominion Resources Services	4	1	Via Webex
22.	Sean Lagan	IESO	Guest	1, 2	
23.	Mohab Elnashar	IESO	Guest	2	
24.	Nazila Rajaei	Hydro One Networks	Guest	2	
25.	Salvatore Spagnolo	NYPA	4	1, 2	Via Webex
26.	Jim Grant	NYISO	2	1, 2	
27.	Mike Jones	National Grid	3	1, 2	
28.	David Kiguel	Independent	7	1, 2	
29.	Joel Charlebois	AESI	7	1, 2	
30.	Quintin Lee	Eversource	1	1, 2	
31.	Kathleen Goodman	ISO-NE	2	1, 2	
32.	Sean Cavote	PSEG	4	1, 2	Via Webex
33.	Jerry Ancona	New York State Department of Public Service	6	1, 2	Via Webex
34.	Laura Mcleod	NB Power	1	1, 2	
35.	Michele Tondalo	Avangrid	1	1, 2	Via Webex
36.	Kristina Henderson	Avangrid	1	1, 2	Via Webex
37.	Allen Schriver	NAGF	Guest	2	Via Webex
38.	Adam Guinn	Duke Energy	Guest	2	Via Webex

Introductions and Chair's Remarks

Payam Farahbakhsh provided a safety session at Hydro One.
Guy Zito welcome everyone to Toronto Canada and provided an update on the NARUC meeting. Guy discussed "black sky" exercise which involves the importance of situation awareness with other utility resources (water, gas and wastewater).

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

Agenda Items:

1.0 Review of Agenda
Guy Zito reviewed the meeting agenda with the RSC group and he made the member aware that the second day DER Forum will not go in order of the agenda.

2.0 RSC Meeting Minutes
Approval of Minutes—no additional revisions were made to the draft RSC meeting minutes of 5-15-19.
Quintin Lee made the motion for approval.
Kathleen Goodman seconded the motion.
The meeting minutes were approved as read.

3.0 Drafting Team Members and Executive Tracking Summary

3.1 NPCC Members on NERC Drafting Teams
The RSC members reviewed the roster and move a few projects into the inactive list because they are completed.

3.2 NERC Project Tracking Spreadsheet
Guy Zito and Ruida Shu provided a brief update on the NERC Project Tracking Spreadsheet.

4.0 Open Action Items

4.1 Open Action Items List
Open Action Item 4.3 is added to the list.

5.0 Items Requiring RSC Discussion

5.1 NERC Weekly Standards Bulletin
Guy Zito reviewed the NERC weekly standards bulletin with the RSC group.

5.2 Regional Standard Processes Manual
Approval of posting the RSPM for a 45-day comment period subject to review of the RSAR and NERC standard template for any necessary alignment--Herb Schrayshuen made the motion for approval.
Mike Jones seconded the motion.
The RSPM is approved for posting.

5.3 New Proposed, Endorsed, and Non-Endorsed Implementation Guidance

Guy Zito and Al McMeekin updated the RSC members on the changes to the implementation guidance.

5.4 FERC TPL-001-5 NOPR

Guy Zito gave a presentation on all the updates to TPL-001-5 Notice of Proposed Rulemaking.

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
Project 2017-01 Modifications to BAL-003-1.1	1/17/19 (F)	1/17/19 (I)
Project 2015-09 Establish and Communicate System Operating Limits	10/17/18 (F)	10/17/18 (I)
Project 2016-02 Modifications to CIP Standards	7/17/19 (F)	7/17/19 (A)
Project 2018-04 Modifications to PRC-024-2	7/26/19 (F)	5/31/19 (I)
Project 2019-01 Modifications to TPL-007-3	9/9/19 (F)	9/9/19 (I)
Project 2019-02 BES Cyber System Information Access Management	4/26/19 (F)	
Project 2019-03 Cyber Security Supply Chain Risks	8/1/19 (I)	
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final		

Project 2015-09 Establish and Communicate System Operating:
Dean Laforest called in at 1:00PM.
The drafting team had a conference call with FERC a couple months ago.
The revisions are attempting to establish IROL and SOL exceedance.
The discussion resulted FERC asking the drafting team to discuss
Three weeks ago, the drafting team had a conference call with the FERC staff and provided data by the drafting team.

Project 2017-01 Modifications to BAL-003-1.1:
Laura Anderson called into the meeting at 1:30PM.
Two phases to this project.
Phase I:
Proposed Standard BAL-003-2 modifies the currently-effective standard and process documents to address:
The inconsistencies in calculation of IFROs due to Interconnection Frequency Response performance changes of Point C and/or Value B;
The Eastern Interconnection Resource Loss Protection Criteria (RLPC);
The frequency of nadir point limitations (currently limited to t0 to t+12);

Clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities;
The BAL-003-1.1 FRS Forms enhancements that include the ability to collect and submit FRSG performance data.
Initial Posting – 45-day comment and ballot period December 4, 2018 to January 17, 2019, with 96.41% approval and 92.02% quorum.
NERC Board adoption November 2019.
Phase II will consider:
Revisions to the Reliability Standard to address the Real-time aspects of Frequency Response necessary to maintain reliability;
Ensuring comparability of and applicability to the appropriate responsible entities;
Developing measurements to incorporate Real-time and resource and load characteristics;
Ensuring equitability of performance.
The project will be posted for a 30-day informal comment period in October 2019.

Project 2018-04 Modifications to PRC-024-2:
Matt Bunch called in at 1:40PM.
The SDT reviewed the comments on the SAR and decided that it is not necessary to modify the SAR. SAR submitted on December 2018.
Updated Terminology: “Protective relays” replaced with “protection” to encompass traditional relays in addition inverter-based protection. “Generator” replaced with “generating resource”. “Collector transformer” replaced with “main-power transformer”.
Identifies applicable protection on equipment that may trip the generator under the facilities section.
Transmission Owners no longer applicable entities (next draft)
Point of Interconnection: Term replaced with “at the high side the GSU/MPT” No changes from PRC-024-2.
Exclusion added for plant auxiliary equipment.
Variance – Quebec Interconnection. More stringent voltage no trip boundaries, boundaries vary based on plant type.
Supplemental SAR accepted by SC on June 26, 2019.
GSU/MPT protection in scope for synchronous machines.
Transformer protection currently in scope for dispersed power-producing resource.
Review applicability for TOs that may own GSUs/MPTs with associated protections.
TOs that own GSUs/MPTs with associated protection not identified as a continent-wide issue in the comment period.
The next SDT meeting will be from September 4-6, 2019 in Austin Texas.
The next ballot will not have transmission owner as an applicable entity.
The team is meeting to finish up posting that ends on October 28, 2019.

Al McMeekin provided an update on the upcoming NERC Projects:
PRC-019 will be one of the upcoming NERC Projects, it involves coordination of limits within the generator itself.
SPIDERWG is working on the MOD-032 SAR and plan to send to SC for approval.
The SAR will be focused on DER.

Project 2019-01 Modifications to TPL-007-3:
Alison Oswald called in at 2:00PM and provided an update on TPL-007-3.
Cynthia Yiu show up in person and provided an update to the Project to the RSC members.
TPL-007-4 needs to address FERC Order 851.
Regulatory filing deadline is by July 2020.
The Commission directs NERC to develop and submit modifications to Reliability Standard TPL-007-2:

1) To require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities
2) To authorize extensions of time to implement corrective action plans on a case-by-case basis.

Requirement R11: Corrective Action Plans (CAP) for supplemental GMD event Vulnerability Assessment. Same 2 and 4 year deadlines for non-hardware and hardware mitigation. Requires prior approval of timeline extensions by Electric Reliability Organization (ERO).
Implementation Guidance is provided with acceptable approaches and boundaries in the figure.
Case by case exceptions are applied to CAP, written into R7 and new R11.
Canadian variance addresses case-by-case extension process by replacing requirement R1 part 7.3 through part 7.5 and requirement R11, part 11.3 through part 11.5.
With Canadian specific language to align with regulatory practices and processes within Canadian jurisdictions.

Project 2019-03 Cyber Security Supply Chain Risks
Alison Oswald continue with her updates on Project 2019-03.
SAR comment period ended on August 1, 2019.
30-day drafting team member solicitation period also ended on August 1, 2019.
Team members will be approved by the Standard Committee members at their August 2019 meeting.
The project is created to address FERC Order 850 and recommendations in the NERC Cyber Security Supply Chain Risks Report.

Project 2016-02 Modifications to CIP Standards:
Norm Dang gave a presentation in person on Project 2016-02.
The drafting team is in the process of reviewing the comments submitted for the CIP-002-6 additional ballot and it is preparing CIP-002-6 for final ballot.
Virtualization case for change white paper is very effective and according to the comments 85%+ comments are positive.
Definitions unchanged are Cyber Asset (CA), Electronic Security Perimeter (ESP) and BES Cyber System (BCS).
New virtualization definitions created are:
Virtual Cyber Asset (VCA): A logical instance of an operating system, firmware, or self-contained application hosted on SCI.
Shared Cyber Infrastructure (SCI): Programmable electronic devices whose compute, storage, or network resources are shared with one or more Virtual Cyber Assets or that perform logical isolation for an ESZ. This includes its management systems.
Electronic Security Zone (ESZ): A security zone is a segmented section of a network that contains systems and components to create logical isolation.

Updated definitions: BES Cyber Asset (BCA), External Routable Connectivity (ERC), Transient Cyber Asset (TCA), EACMS, Protected Cyber Asset (PCA) and Removable Media (RM). Retired the following definitions: Electronic Access Point (EAP) and Electronic Access Control or Monitoring System (EACMS).
The approach is to allow old style/configurations remain and create virtualization specific controls alongside for: ESZ, SCI, Virtualized BCAs, EACS, PACS, PCAs etc.
Norm also reviewed the new proposed requirements of CIP-005-7 with the group.
The goal is to get through CIP-005-7 first then the drafting team will focus on CIP-007 and CIP-010. The drafting team will preserve Cyber Asset term for backwards compatibility, and using new terms to help describe the virtual environment as we move toward technology agnostic requirements.

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

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

7.0 NERC Drafting Team Nominations

7.1 Currently Posted Drafting Team Vacancies

Ruida Shu discussed with the RSC members in regards to the two drafting team currently soliciting members. Project 2019-04 PRC-005-6 and Project 2019-05 PER-003-3.

7.1.1 None at this time

7.2 Closed Drafting Team Nominations (Since last RSC Meeting)

7.2.1 None at this time

7.3 Solicitation for Informal Development Teams

7.3.1 None at this time

8.0 NPCC Regional Reliability Standards

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

8.1 Current Activities:

8.1.1 PRC-006-NPCC-2 Automatic Underfrequency Load Shedding Standard status update.
Due to an errata in the PRC-006-NPCC-2 standard it will require the standard to be resent to the NPCC BOD for endorsement.
Ruida Shu showed the errata in Figure 1 to the members of RSC and seek RSC members to approve the typo errata on Figure 1 of the PRC-006-NPCC-2. Changed from (0.1s – 1.1s) to (0.1s – 2.0s).
Herb Schrayshuen made the motion to make the typo change on Figure 1 of PRC-006-NPCC-2.
Brian Robinson seconded the motion.
The errata/typo is corrected in the Figure 1 of PRC-006-NPCC-2.

9.0 NPCC Non-Standards

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

9.1 Items for Discussion:

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

(Status of RAS Implementation/Transition)

The TFCP is coordinating revisions to Directory #7 Appendix B which provides the regional review process for new, revised or retired SPS's. The TFCP review will insure that the Appendix B process is consistent with PRC-012-2. The TFCP will circulate the final revised version of Appendix B to the TFSS, the TFSP and the TFCO prior to incorporating the revised Appendix B into the draft of D#7. The TFSP is reviewing the Directory#7 criteria and will incorporate Appendix B into the posted revised draft of Directory#7. TFSP anticipates posting D#7 late 2019 early 2020.

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

The revised A-10 was posted to the Open Process and the CP-11 has compiled comment responses and revised the posted draft as necessary. CP-11 presented the draft comment responses and revised draft to the TFCP AND A SECOND Open Process posting will commence in late August. TFCP anticipates presenting a final revised A-10 draft to the RCC in December with a Full Member ballot subsequent to RCC approval.

9.1.3 BOD Approved Corporate Goal:

(Cost Effective Pilot ---- Directory #4 and Directory#5)

Status of Open Process Posting.

As a follow up to the Strategic Review of the NPCC Criteria a cost-effective survey accompanied the Open Process postings of Directory #4 System Protection Criteria and Directory#5 Reserve. The surveys were used as a pilot to solicit cost effective details on the incremental contribution to reliability, system resilience and cost effectiveness of the criteria. The TFSP and TFCO have reviewed the survey results which will be incorporated into the record of the Directories review. Additionally, the surveys informed the development of a permanent and repeatable process to consider cost effectiveness during future Directory reviews. This process will be incorporated into the Directory Development and Review Manual.

9.1.4 Other Items

9.2 Items for Approval:

9.2.1 Directory Manual ----- RSC Approval

Repost Revised Directory Manual

The RSC reviewed draft responses to comments received during the Open Process posting of the Directory Development and Revision Manual. The revised Manual contains a draft cost effective survey which has been developed based on responses to the cost effective surveys accompanying Directory # 4 System Protection Criteria and Directory #5 Reserve. The

revised Directory Manual containing additional revisions as a result of comments received during the initial Open Process posting will be posted for a second Open Process comment period in late August.

9.3 Executive Tracking Summary

C-33 --- Procedure for Analysis and Classification of Dynamic Control Systems:
Pending TFCP concurrence TFSS has proposed retiring C-33 and making conforming changes to Directory#1 Appendix B.

Directory#5 Reserve and Directory#6 Reserve Sharing Groups:
TFCO has reviewed and updated both Directories and will present D#5 and D#6 to the RCC in September. Following anticipated RCC approval a Full Member ballot will be conducted on both documents in mid-September.

10.0 RSC Member Items of Interest

10.1 RSC Roster

Ruida Shu reviewed the RSC roster with the RSC group.

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 23rd – Call	February 20th – Call	March 20th – Austin TX (Austin Energy)
April 17th – Call	May 22nd – Call	June 26th – Atlanta GA (NERC)
July 24th – Call	August 21st – Call	September 18th – Kansas City MO (KCP&L)
October 23rd – Call	November 20th – Call	December 18th – Atlanta GA (NERC)

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

February 6-7 - Meeting	May 8-9 - Meeting	August 14-15 - Meeting
November 5-6 - Meeting		

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

13.0 NERC Items of Interest (Since last RSC Meeting)

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

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

13.2 Alerts

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

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

14.0 Other Items of Interest

14.1 NPCC Board of Directors Meeting (BOD) 2019

January 30th – ISO-NE Backup Control Center, Windsor CT	March 20th - Call	May 1st – NPCC Office
June 5th – Call	June 26th – NPCC Office	August 7th – Call
September 4th and 5th – Halifax, Nova Scotia	October 30th – Call	December 4th – Montreal, Quebec

14.2 NPCC and ERO 2020 Business Plan and Budget Schedule

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2019 Meeting Date

February 13th-14th, Eversource, Boston MA
May 15th-16th, Saratoga NY
August 7th-8th, Hydro One Toronto Canada
October 16th-17th, Lewiston NY
December 5th, 2019 Montreal Canada (General Meeting)

Day Two DER Forum:

Participants via Webex:

	Name	Organization	Comment
1.	Aaron Hornick	NPCC	Via Webex
2.	Adam Quinn	Duke Energy	Via Webex
3.	Alex Rost	ISO-NE	Via Webex
4.	Arun Narang	Hydro One	Via Webex
5.	Ben Carron	SunRun	Via Webex
6.	Allen Schriver	NAGF	Via Webex
7.	Bob Manning	UI	Via Webex
8.	Bruce Jagolinzer	Central Maine Power	Via Webex
9.	Chelsea Zhu	NY-ISO	Via Webex
10.	Chris Overberg	Con Edison	Via Webex
11.	Chris Vance	National Grid	Via Webex
12.	Clothier Bryce	Nova Scotia Power	Via Webex
13.	Constantin Chitescu	OPG	Via Webex
14.	Dan Kopin	Utility Services	Via Webex
15.	David Conroy	Central Maine Power	Via Webex
16.	David Gordon	MMWEC	Via Webex
17.	David Kiguel	Independent	Via Webex
18.	Dhaval Patel	Hydro One	Via Webex
19.	Donald Nelson	Commonwealth of MA Electric Power D	Via Webex
20.	Dylan Dreisch	PSEG	Via Webex
21.	Ed Roedel	Avangrid	Via Webex
22.	Eryk Zalewski		Via Webex
23.	Edvard Lauman		Via Webex
24.	Gabriel Adam		Via Webex
25.	Gene Ng	Hydro One	Via Webex
26.	Gavin Li	PSEG	Via Webex
27.	George Smith	NYSRC	Via Webex
28.	Herb Schrayshuen	Power Advisors, LLC	Via Webex
29.	Jasminder Madra		Via Webex
30.	Jerry Ancona	NYDPS	Via Webex
31.	Jim Grant	NY-ISO	Via Webex
32.	Joe Farella	National Grid	Via Webex
33.	Joel Charlebois	AESI	Via Webex
34.	John Charlton	Nova Scotia Power	Via Webex
35.	John Ng		Via Webex
36.	John Pearson	ISO-NE	Via Webex
37.	John Romano		Via Webex
38.	Kal Ayoub	FERC	Via Webex
39.	Keith Burrell		Via Webex
40.	Klearko Goro	PSEG	Via Webex
41.	Kristina Henderson	Avangrid	Via Webex
42.	Michael Lombardi	NPCC	Via Webex
43.	Michael Ridolfino	Central Hudson	Via Webex
44.	Michele Tondalo	Avangrid	Via Webex

45.	Nazila Rajaei	Hydro One	Via Webex
46.	Nate Pelletier		Via Webex
47.	Nicolas Compass	Hydro Quebec	Via Webex
48.	Nimish Bhatnagar		Via Webex
49.	Nurul Abser	NB Power	Via Webex
50.	Per-Anders Lof	National Grid	Via Webex
51.	Peter Davie	PSEG	Via Webex
52.	Peter Van Huynh	Nova Scotia Power	Via Webex
53.	Qinling Zheng	Con Edison	Via Webex
54.	Rich Heidorn Jr.	RTO Insider/ERO Insider	Via Webex
55.	Robert Eisenhuth		Via Webex
56.	Quang Nguyen		Via Webex
57.	Roger Clayton	NYSRC	Via Webex
58.	Roman Solomonyuk		Via Webex
59.	Sal Spagnolo	NYPA	Via Webex
60.	Sean Cavote	PSEG	Via Webex
61.	Sean Bodkin	Dominion	Via Webex
62.	Thinh Pham		Via Webex
63.	Tony Napikoski	UI	Via Webex
64.	Yves Albert	NB Power	Via Webex

16.0 Distributed Energy Resources (DER) Forum Topics

16.1 DER, Approach to Regional Guidance and DER Impact Reporting
Herb Schrayshuen provided an update on the 30-day comment period on the NPCC Guidance documents.
There are about 124 comments submitted to NPCC and Herb is working on analyze and respond to each of the comments.

16.2 NERC SPIDER Working Group Presentation by Utility Services
The NERC Spider Working Group studying DER integration from a Transmission level perspective. Spider WG has subgroups focused
on modeling, verification, studies, and coordination. Spider will defer the development of a DER Glossary definition.
MOD-032-1 will be revised to include the Distribution Provider in the applicability.
Spider WG is looking at mechanisms to ensure that there is not too much DER on a UFLS feeder, adaptive UFLS design.

16.3 Impacts of DERs in Ontario presentation by Mohab Elnashar from IESO
IESO conducts an Operability Assessment which address DER concerns.
Operations concerns focus on system inertia and primary frequency response.
Ontario has approximately 4000 MWs of DER. Is there a single contingency that can potentially trip all 4000 MWs?
Currently working with OEB to modify distribution system code by adopting the Canadian Standard Association rules on DER performance.

16.4 DER current state presentation by Nicolas Compas from Hydro Quebec
Hydro Quebec is currently 99% renewable (Hydro and Wind)
Hydro Quebec anticipates 5% Solar penetration by 2030.
Hydro Quebec exploring dual strategies regarding integration of DER proactive and reactive.
Hydro Quebec has a “Scenario Project” which utilizes a bottom up approach to DER integration.

16.5 Inverter Based Resources presentation by NAGF
NAGF monitoring DER developments.
IEEE P-2800 standard for Interconnection of DER.
Significant operational issue for G.O.’s are the increased maintenance costs and associated loss of revenue as a result of generators chasing and ramping solar variability for the BA’s.

16.6 Hydro One DER Update presented by Adnan Akhtar
Currently 4000MWs of DER in Ontario. Wind, Solar, biomass and Hydroelectric.
As a result of the regulatory landscape in Ontario, there is no incentive for DER to connect post 2018.
DER provide load displacement, peak shaving, no-parallel load displacement.
Short Circuit constraint impacting the transmission system, solutions are typically very expensive, BT’s or Reactors.
Ontario has publicly available documents containing DER interconnection

requirements (TIR – Technical Interconnection Requirements).

16.7 Duke Energy Project on DER presented by Adam Guinn
Real-time Integration and Monitoring of DER.
Primarily Solar, significant operational issue is chasing solar variability with conventional generation. BA's are struggling with ramping issues based on the solar variability.
DER Solar facilities typically range from 25 to 88MWs. Many solar facilities are deliberately designed with a capacity below 75MWs, in order to avoid the NERC registry.
Telemetry available for approximately 97% of the DER resources. Gross Generation is typically monitored.
UFLS feeders with solar are impacting overall UFLS program by diminishing available load to be shed. A dynamic UFLS program in R/T monitors UFLS capability.

16.8 SunRun Presentation on DER by Ben Carron

The meeting is adjourned at 11:59AM on August 8, 2019.

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**
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		
2016-02	Modification to CIP Standards	Standard	Norm Dang	IESO		
2016-EPR-01	Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards	Standard	Tim Kucey	PSEG Fossil, LLC		
2017-01	Modifications to BAL-003-1.1	Standard	Jessica Tang	IESO		
2017-07	Standards Alignment with Registration	Standard	Mark Atkins	AESI		
2018-02	2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	Standard	Norm Dang	IESO		
2018-04	Modifications to PRC-024-2	Standard	Noel Aubut Tracy Macnicoll	Hydro Quebec Utility Services		
SER	Standard Efficiency Review	Standard	Greg Campoli (Advisers) Michael Puscus (Advisers)	NYISO ISO-NE		
2019-01	Modifictions to TPL-007-3	Standard	Per-Anders Lof (Vice Chair) Rui Sun Jow Ortiz Cynthia Yiu	National Grid Dominion Florida Power & Light (NextEra Energy) Hydro One		
2019-02	BES Cyber System Information Access Management	Standard				
2019-03	Cyber Security Supply Chain Risks	Standard				
2019-04	Modifications to PRC-005-6	Standard				
2019-05	Modifications to PER-003-2	Standard				

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Updated: 10/9/2019

Nom-SAR/ QR Posting-SAR or Pos

HOME

Upda	List of Approved Projects (Filter)	DO NOT SORT (Filtering Ok) Deliverables (Filter)	Early/(Late) Days (Filter)	Baseline/ Current (Filter)
	2015-09 - Establish and Communicate System Operating	CIP-014-3, FAC-003-5, FAC-011		Current
	2015-09b - Establish and Communicate System Operatin	IROL Stds.		On Hold
	2016-02c - Modifications to CIP Standards	CIP-002-6 - Address TO Contro	(825)	Current
	2017-01 - Modifications to BAL-003-1.1	BAL-003-2	(177)	Current
	2017-01b - Modifications to BAL-003-1.1	BAL-003-2	(233)	Proposed
	2017-03 - Periodic Review of FAC-008-3 Standard	PR Recommendations		On Hold
	2017-04 - Periodic Review of Interchange Scheduling anc	PR Recommendations		On Hold
	2017-05 - Periodic Review NUC-001-3	PR Recommendations		On Hold
	2017-07 - Stds Alignment with Registration	Standards with PSE, IA, or LSE	(401)	Proposed
	2018-04 - Modifications to PRC-024-2	PRC-024-3	(56)	Current

2019
Oct Nov Dec

1 **SUMMARY**
2 Tutorial Video (11 min)
3 Click here to report errors or issues
4 **Tabs** along the bottom of the spreadsheet:
5 **Green tab** - Home Page listing all active projects
6 **Yellow tabs** - Help, Summary Page of projects, and Footnotes (far right tab)
7 **Blue tabs** - Indicate an active project.
Red tabs - Indicate a non-active project and are generally not shown, but may be revealed by "unhiding" the tab. If a red tab has an "underscore" preceding the project number (e.g., _YYYY-##) it means the project was added for developing metrics on previous projects not
8 initially populated in this tracker.
Project Number nomenclature: The year started and the sequence (YYYY-##), a letter or .#/.alphabet letter denote the project was split into phases for tracking purposes. Phased projects in the tracker may or may not reflect the project being "Phased" on the www.nerc.com
9 website.
10 **Home Page -** Gannt chart of active projects with current or proposed schedules, tyically set with the baseline schedule not showing.
11 Home Page - Filter is OKAY. Sorting will misalign the conditional formatting of the Gannt Chart.
12 Home Page - Column "B" is a freshness indicator of the underlying project page.
13 Home Page - Column "C" is the project name with an in document hyperlink to the respective project tab
14 Home Page - Column "D" lists the deliverables identified on the individual project pages
15 Home Page - Column "E" lists the number of days early or (late) a project is running based on the approved baseline schedule final ballot date.
16 Home Page - Column "F" lists the current status of the project "schedule" (See Note 6 in the footnotes for more information).

Home Page - Remaining columns to the right color code the what is anticipated in the project schedule. Proposed means the projected schedule or that it has been completed. If the projects are filtered on "baseline" the PMOS approved schedure is shown. To see previous
17 time or future times, simply "unhide" the applicable columns using the spreadsheet functions.
18

Project	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
SUMMARY	(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
2015-09	Establish and Communicate System Operating Limits	Working to Additional Ballot	The standard drafting team (SDT) is working on proposed language for FAC-011 Requirements. The SDT most recently proposed that a System Operating Limit (SOL) Exceedance only has to be reported if it exceeds 30 minutes. The SDT is holding a conference call on October 8, 2019 and an in-person meeting November 19-21, 2019. The plan is to post late December or early January.	CIP-014-3, FAC-003-5, FAC-011-4, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026 and the retirement of FAC-010	N/A	Footnote 7, Medium	N/A			N/A	Latrice Harkness & Darrel Richardson	Ken Lanehome	CIP-014-3, FAC-003-5, FAC-011, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-1 and the retirement of FAC-010	10/3/2019
2015-09b	Establish and Communicate System Operating Limits	SDT Development	The IROL portion of the project has been placed on hold pending additional information. The SDT decided that IROL modifications will not be made to CIP-002 at this time. The CIP SDT (2016-02c) will finish their work and post with no changes to the IROL language. CIP-002 will be re-opened during phase 2 of this project to address the IROL language.	IROL Stds.	N/A	Medium	N/A	1	1	N/A	Latrice Harkness & Darrel Richardson	Ken Lanehome	TBD - On Hold	10/3/2019
2016-02c	Modifications to CIP Standards	Working to Additional Ballot	The team will move Planned and Unplanned Changes back to the Implementation Plan based on comments received. This will require an additional 45-day ballot on or about October 29, 2019. The documents are currently going through a quality review.	CIP-002-6 - Address TO Control Centers Performing Transmission Operator (TOP) Obligations.	N/A	Footnote 8, High	N/A			N/A	Jordan Mallory	Ken Lanehome, Ash Mayfield, and Kirk Rosener	CIP-002-5.1a	10/9/2019
2016-02d	Modifications to CIP Standards	Responding to Comment	CIP-005 45-day posting ended September 26, 2019 and the SDT is reviewing comments received. Other standards (CIP-007 and CIP-010) are planned for posting in late November 2019.	Address all remaining V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), Obligations, Virtualization, and CIP Exceptional	N/A	Footnote 8, High	N/A			N/A	Jordan Mallory	Ken Lanehome, Ash Mayfield, and Kirk Rosener	CIP-004, CIP-005, CIP-006, CIP-007 and CIP-010	10/9/2019
2017-01	Modifications to BAL-003-1.1	Working to Final Ballot	The SDT is meeting October 8-10 and NERC staff (Brad Gordon) will present the study findings. If the SDT accepts the study findings, the project will proceed to final posting. Final ballot Phase I posting dates have been requested for October 9-18, 2019. Anticipating Phase I will pass final ballot, the project will be presented at the Board of Trustees meeting November 2019 for adoption.The project is nearing completion and is about two quarters behind schedule.	BAL-003-2	N/A	Footnote 8, Medium	N/A			N/A	Laura Anderson	Amy Casuscelli & Linda Lynch	BAL-003-1.1	10/9/2019
2017-01b	Modifications to BAL-003-1.1	Working to Initial Ballot	Smaller sub-teams were formed to work on specific requirements in the standard. The SDT has an in-person meeting scheduled October 8-10, 2019 to finalize the documents for a 45-day posting for formal comment and an initial ballot and to finalize the project timeline. The SC anticipates seeking SC authorization to post in October 2019.	BAL-003-2	N/A	Footnote 8, Medium	N/A			N/A	Laura Anderson	Amy Casuscelli & Linda Lynch	BAL-003-1.1	10/9/2019
2017-03	Periodic Review of FAC-008-3 Standard	On Hold	The periodic review team delivered their review recommendation to the SC in March 2018. The recommendation is to reaffirm with an action to revise, but at a later time. No action will be taken or archiving of the PTS item until the Standards Efficiency Reviews are complete.	PR Recommendations	N/A	Footnote 9, Low (was Medium previously)	N/A			N/A	Jordan Mallory	Mark Pratt	FAC-008-3	10/9/2019

Project	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
SUMMARY	(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
2017-04	Periodic Review of Interchange Scheduling and Coordination Standards	Other	There will be an informational update to the Board in February 2020 that the project will be closed due to the stanard version being superceded.	PR Recommendations	N/A	Footnote 9, Low (was Medium previously)	N/A			N/A	Laura Anderson	Charles Yeung	INT-004, INT-006, INT-009, and INT-010	10/9/2019
2017-05	Periodic Review NUC-001-3	On Hold	The review template 45-day posting for preliminary recommendations ended January 29, 2018. There is a meeting scheduled for March 19 to review industry comments and discuss the team's final recommendation. Given the overwhelming industry support for the team's Preliminary Recommendation (Yellow-Revise), they do not anticipate a change in the recommended "color" of the standard. The PRT recommends to reaffirm the standard and has placed the project on hold pending the Standards Efficiency Reivew outcomes.	PR Recommendations	N/A	Footnote 9, Low (was Medium previously)	N/A			N/A	Jordan Mallory	Amy Casuscelli and Colby Bellville	NUC-001-3	10/9/2019
2017-07	Stds Alignment with Registration	Working to Initial Ballot	The project has been reactivate and the team plans to meet in mid December 2019. The project is not as simple as just removing a requirement with PSE, IA or LSE. The removal of the requirement may create a gap that would need to be addressed by another functional entity such as Distribution Provider (DP) or Transmission Owner (TO). The team is anticipating going to the SC for approval to do an initial posting and ballot in October or later.	Standards with PSE, IA, or LSE		Footnote 9, Low	N/A			N/A	Laura Anderson	Mike Brytowski	Standards with PSE, IA, or LSE (CIP-002 through CIP-011, FAC-002, INT-004, IRO-010, MOD-031, MOD-032, NUC-001, TOP-003)	10/9/2019
2018-04	Modifications to PRC-024-2	Posted	The project documents are posted for an additional comment period and ballot through November 4, 2019.	PRC-024-3	N/A	N/A	N/A			N/A	Latrice Harkness & Alison Oswald	Linda Lynch	PRC-024-2	10/9/2019
2019-01	Modifications to TPL-007-3	Responding to Comment	The TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events passed initial ballot and will go to final ballot the week of November 11, 2019.	TPL-007-4	6/30/2020		N/A	1		N/A	Alison Oswald	Michael Brytowski	TPL-007-3	10/9/2019

Project	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
SUMMARY	(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
2019-02	BES Cyber System Information Access Management	SDT Development	Supplemental members are planned to be appointed to the team at the October 23, 2019 Standards Committee meeting. The SDT continues to work on revisions to CIP-004 and CIP-011 and made revisions to move Requirements related to BCSI access to CIP-011. This change helps to consolidate all BCSI-related requirements in one CIP Standard. The team is also developing the supporting	TBD	N/A		N/A			N/A	Latrice Harkness	Colby Bellville and Kirk Rosener	CIP-004 and CIP-0011	10/9/2019
2019-03	Project 2019-03 Cyber Security Supply Chain Risks	Responding to Comment	It is anticipated the Standards Committee will appoint SAR team as the SDT. The SDT will meet in-person on November 19-21, 2019.	CIP-005-6, CIP-100-3, and CIP-013-1	12/25/2020		N/A	1		N/A	Alison Oswald	Linda Lynch (Primary) and Kirk Rosener (Secondary)	CIP-005-6, CIP-010-3, and CIP-013-1	10/9/2019
2019-04	Modifications to PRC-005-6	Nominations	The Standards Committee accepted the Standard Authorization Request (SAR) on July 24, 2019 and authorized the SAR for a 30-day formal posting and comment period. Nominations for the Standard Authorization Request drafting team members ended August 28, 2019 along with the formal comment period for the SAR. NERC staff plan to seek an additional solicitation for team members.	PRC-005			N/A			N/A	Laura Anderson	Mark Pratt and Linda Lynch	PRC-005-6	10/9/2019
2019-05	Modifications to PER-003	SDT Development	The SAR comment period ended August 30, 2019. NERC is currently vetting nominations for the SAR drafting team to present to the Standards Committee on October 23, 2019.	PER-003			N/A			N/A	Alison Oswald	Colby Bellville and Kirk Rosener	PER-003	10/9/2019

PMOS ROSTER & LIAISON PROJECT BURDEN																						HOME
Position	**Term**	**Name**	**Entity**	**# Std.**	2015-09	2015-09b	2016-02c	2016-02d	2017-01	2017-01b	2017-03	2017-04	2017-05	2017-07	2018-04	2019-01	2019-02	2019-03	2019-04	2019-05	2019-06	Insert New
Chair	2019-2020	Charles Yeung	Southwest Power Pool, Inc.	5								4								1		
Vice Chair	2018-2019	Michael Brytowski	Great River Energy	19										18		1						
Member	2018-2019	Colby Bellville	Cooperative Energy	4									1				2			1		
Member	2019-2020	Ken Lanehome	Bonneville Power Administration	14	7	1	1	5														
Member	2018-2019	Linda Lynch	NextEra Energy | Florida Power & Light	4					1	1					1				1			
Member	2019-2020	Ash Mayfield	Grand River Dam Authority	6			1	5														
Member	2018-2019	Mark Pratt	Southern Company	2							1								1			
Member	2018-2019	Kirk Rosener	CPS Energy	9			1	5									2	1				
Non-voting Members	SC Chair	Andrew Gallo	City of Austin, dba Austin Energy	0																		
Non-voting Members	SC Vice Chair	Amy Casuscelli	Xcel Energy	3					1	1			1									
NERC Staff	NERC Staff	Scott Barfield-McGinnis, Secretary	North American Electric Reliability Corporation	0																		
NERC Staff	NERC Staff	Marisa Hecht, Legal	North American Electric Reliability Corporation	0																		
INSERT NEW ROW				0																		

Project	**Standards Efficiency Review**	**Home**
Project Name	Overview for PMOS	
Status	Other	
Comments	The Standards Authorization Request was posted through September 26, 2018. The drafting team will be having the kick-off meeting on November 6, 2018, see the NERC calendar for details.	
Deliverable		
Operations Planning Subteam	Amy Casuscelli & Charles Yeung	
Real-time Operations Subteam	Mike Brytowski	
Long-term Planning Subteam	Linda Lynch	
SER Phase 1	Mike Brytowski & Mark Pratt	
SER Phase 2 (Concepts)	Mike Brytowski & Linda Lynch	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Chris Larson	
PMOS Liaison	Mark Pratt & Michael Brytowski	
Affected Standards	See SAR (too many to list)	
Last Updated	6/25/2019	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
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							

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
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

Project	**2015-09**				**Home**
Project Name	Establish and Communicate System Operating Limits				
Status	Working to Additional Ballot				
Comments	The standard drafting team (SDT) is working on proposed language for FAC-011 Requirements. The SDT most recently proposed that a System Operating Limit (SOL) Exceedance only has to be reported if it exceeds 30 minutes. The SDT is holding a conference call on October 8, 2019 and an in-person meeting November 19-21, 2019. The plan is to post late December or early January.				
Deliverable	CIP-014-3, FAC-003-5, FAC-011-4, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026 and the retirement of FAC-010				
Deadline	N/A				
Priority in RSDP, click to see applicable Footnote	Footnote 7, Medium	**Priority (1-Low, 2-Med, 3-High)**	2	**Project has been Re-Baselined? (0-No, 1-Yes)**	1
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	Latrice Harkness & Darrel Richardson				
PMOS Liaison	Ken Lanehome				
Affected Standards	7	CIP-014-3, FAC-003-5, FAC-011, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-1 and the retirement of FAC-010			
Last Updated	10/3/2019				

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review			4/4/2016	4/14/2016		Not needed	

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
SP1 - SAR/PR/WP Posting 1	8/20/2015	9/21/2015	8/20/2015	9/21/2015			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	7/14/2016	8/12/2016	7/8/2016	8/7/2016	(6)		
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/29/2017	11/13/2017	9/22/2017	11/5/2017	(7)		Posting date changed see notes 8/10 and 8/25.
CAB - Com/Add Ballot 2	8/24/2018	10/17/2018	1/17/2018	3/2/2018	(219)		
CAB - Com/Add Ballot 3	1/9/2020	2/23/2020	8/26/2019	10/10/2019	(136)		**6/26/19 baseline starts here**
CAB - Com/Add Ballot 4	12/18/2019	2/1/2020	12/18/2019	2/1/2020			
CAB - Com/Add Ballot 5							
FB - Final Ballot	2/11/2020	2/21/2020	2/11/2020	2/21/2020			
PTB - Present to BOT	5/13/2020	5/15/2020	5/13/2020	5/15/2020			
Filing - Filing with Regulators	6/14/2020	6/17/2020	6/14/2020	6/17/2020			
PT - Post Approval Training							

Project	**2015-09b**			**Home**
Project Name	Establish and Communicate System Operating Limits			
Status	SDT Development			
Comments	The IROL portion of the project has been placed on hold pending additional information. The SDT decided that IROL modifications will not be made to CIP-002 at this time. The CIP SDT (2016-02c) will finish their work and post with no changes to the IROL language. CIP-002 will be re-opened during phase 2 of this project to address the IROL language.			
Deliverable	IROL Stds.			
Deadline	N/A			
Priority in RSDP, click to see applicable Footnote	Medium	**Priority (1-Low, 2-Med, 3-High)**	2	**Project has been Re-Baselined? (0-No, 1-Yes)**
P81 Req (2013)	N/A			
Number of Directives	1	Confirm		
No. of Guidances (see Note 2)	1	Confirm		
Directionally consistent with IERP findings (See Note 5)	N/A			
Developer	Latrice Harkness & Darrel Richardson			
PMOS Liaison	Ken Lanehome			
Affected Standards	TBD - On Hold			
Last Updated	10/3/2019			

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							

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
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							

Project	**2016-02c**	**Home**
Project Name	Modifications to CIP Standards	
Status	Working to Additional Ballot	
Comments	The team will move Planned and Unplanned Changes back to the Implementation Plan based on comments received. This will require an additional 45-day ballot on or about October 29, 2019. The documents are currently going through a quality review.	
Deliverable	CIP-002-6 - Address TO Control Centers Performing Transmission Operator (TOP) Obligations.	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, High	**Priority (1-Low, 2-Med, 3-High)** 3 **Project has been Re-Baselined? (0-No, 1-Yes)** 1
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	Jordan Mallory	
PMOS Liaison	Ken Lanehome, Ash Mayfield, and Kirk Rosener	
Affected Standards	1 CIP-002-5.1a	
Last Updated	10/9/2019	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review	10/20/2016	10/30/2016	10/20/2016	10/30/2016			
SP1 - SAR/PR/WP Posting 1	3/23/2016	4/21/2016					
SP2 - SAR/PR/WP Posting 2							

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
CP1 - Comment Period 1	3/14/2017	4/11/2017					Added to schedule, reduced period - SDT needed feedback
CP2 - Comment Period 2	6/14/2018	7/13/2018					IROL for CIP-002
CIB - Com/Ballot 1 (Initial)	9/14/2017	10/30/2017	12/2/2016	1/15/2017	(286)		See notes for 8/10 and 8/25.
CAB - Com/Add Ballot 2	3/16/2018	4/30/2018	3/31/2017	5/14/2017	(350)		
CAB - Com/Add Ballot 3	8/23/2018	10/9/2018	8/15/2017	9/28/2017	(373)		Going back to initial ballot
CAB - Com/Add Ballot 4	6/3/2019	7/17/2019					Ballot Pools re-opened
CAB - Com/Add Ballot 5	10/29/2019	12/13/2019					
FB - Final Ballot	1/20/2020	1/30/2020	10/17/2017	10/27/2017	(825)		
PTB - Present to BOT	2/5/2020	2/7/2020	11/7/2017	11/9/2017	(820)		
Filing - Filing with Regulators	3/8/2020	3/11/2020	12/28/2017	12/31/2017	(801)		
PT - Post Approval Training							

Project	**2016-02d**			**Home**
Project Name	Modifications to CIP Standards			
Status	Responding to Comment			
Comments	CIP-005 45-day posting ended September 26, 2019 and the SDT is reviewing comments received. Other standards (CIP-007 and CIP-010) are planned for posting in late November 2019.			
Deliverable	Address all remaining V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), Obligations, **Virtualization,** and CIP Exceptional Circumstances. Team is working on CIP-007 and CIP-010 while CIP-005 and the associated definitions are out for comment.			
Deadline	N/A			
Priority in RSDP, click to see applicable Footnote	Footnote 8, High	**Priority (1-Low, 2-Med, 3-High)**	3	**Project has been Re-Baselined? (0-No, 1-Yes)**
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	Jordan Mallory			
PMOS Liaison	Ken Lanehome, Ash Mayfield, and Kirk Rosener			
Affected Standards	5	CIP-004, CIP-005, CIP-006, CIP-007 and CIP-010		
Last Updated	10/9/2019			

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT	2/28/2019	3/29/2019	2/28/2019	3/29/2019			
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	5/30/2019	6/28/2019	5/30/2019	6/28/2019			Case for Change WP
SP2 - SAR/PR/WP Posting 2							

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
CP1 - Comment Period 1	8/9/2019	9/26/2019	8/1/2019	8/31/2019	(8)		
CP2 - Comment Period 2	11/1/2019	12/1/2019	11/1/2019	12/1/2019			
CIB - Com/Ballot 1 (Initial)	3/13/2020	4/27/2020	3/13/2020	4/27/2020			
CAB - Com/Add Ballot 2	6/22/2020	8/6/2020	6/22/2020	8/6/2020			
CAB - Com/Add Ballot 3	9/18/2020	11/2/2020	9/18/2020	11/2/2020			
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	11/16/2020	11/26/2020	11/16/2020	11/26/2020			
PTB - Present to BOT	12/15/2020	12/17/2020	12/15/2020	12/17/2020			
Filing - Filing with Regulators	1/16/2021	1/19/2021	1/16/2021	1/19/2021			
PT - Post Approval Training							

Project	**2017-01**			**Home**
Project Name	Modifications to BAL-003-1.1			
Status	Working to Final Ballot			
Comments	The SDT is meeting October 8-10 and NERC staff (Brad Gordon) will present the study findings. If the SDT accepts the study findings, the project will proceed to final posting. Final ballot Phase I posting dates have been requested for October 9-18, 2019. Anticipating Phase I will pass final ballot, the project will be presented at the Board of Trustees meeting November 2019 for adoption.The project is nearing completion and is about two quarters behind schedule.			
Deliverable	BAL-003-2			
Deadline	N/A			
Priority in RSDP, click to see applicable Footnote	Footnote 8, Medium	**Priority (1-Low, 2-Med, 3-High)**	2	**Project has been Re-Baselined? (0-No, 1-Yes)**
P81 Req (2013)	N/A			
Number of Directives	N/A			
No. of Guidances (see Note 2)	N/A			
Directionally consistent with IERP findings (See Note 5)	N/A			
Developer	Laura Anderson			
PMOS Liaison	Amy Casuscelli & Linda Lynch			
Affected Standards	1 BAL-003-1.1			
Last Updated	10/9/2019			

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	6/19/2017	7/3/2017	6/19/2017	7/3/2017			
Nominations - DT	7/27/2017	8/9/2017	7/27/2017	8/9/2017			Supplemental Nominations
QR - Quality Review							

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
SP1 - SAR/PR/WP Posting 1	6/19/2017	7/18/2017	6/19/2017	7/18/2017			By NERC RS
SP2 - SAR/PR/WP Posting 2	11/2/2017	12/1/2017	11/2/2017	12/1/2017			By NWPP FRSG
CP1 - Comment Period 1	9/6/2018	9/20/2018					Unscheduled posting
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	12/4/2018	1/17/2019	11/6/2018	1/9/2019	(28)		Passed at 96.41%
CAB - Com/Add Ballot 2			2/18/2019	4/3/2019			Balloting again due to comments
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	**10/10/2019**	**10/20/2019**	4/16/2019	**4/26/2019**	(177)		
PTB - Present to BOT	11/6/2019	11/9/2019	5/9/2019	5/12/2019	(181)		
Filing - Filing with Regulators	12/9/2019	12/12/2019	6/9/2019	6/12/2019	(183)		
PT - Post Approval Training							

Project **2017-01b** Home

Project Name	Modifications to BAL-003-1.1
Status	Working to Initial Ballot
Comments	Smaller sub-teams were formed to work on specific requirements in the standard. The SDT has an in-person meeting scheduled October 8-10, 2019 to finalize the documents for a 45-day posting for formal comment and an initial ballot and to finalize the project timeline. The SC anticipates seeking SC authorization to post in October 2019.
Deliverable	BAL-003-2
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, Medium
Priority (1-Low, 2-Med, 3-High)	2
Project has been Re-Baselined? (0-No, 1-Yes)	
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Laura Anderson
PMOS Liaison	Amy Casuscelli & Linda Lynch
Affected Standards	1 BAL-003-1.1
Last Updated	10/9/2019

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							

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
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	11/28/2019	1/12/2020	8/22/2019	10/6/2019	(98)		
CAB - Com/Add Ballot 2	3/2/2020	4/16/2020	11/25/2019	1/9/2020	(98)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	10/1/2020	10/11/2020	2/11/2020	2/21/2020	(233)		
PTB - Present to BOT	11/3/2020	11/6/2020	5/13/2020	5/16/2020	(174)		
Filing - Filing with Regulators	12/6/2020	12/9/2020	6/15/2020	6/18/2020	(174)		
PT - Post Approval Training							

Project	**2017-03**			**Home**
Project Name	Periodic Review of FAC-008-3 Standard			
Status	On Hold			
Comments	The periodic review team delivered their review recommendation to the SC in March 2018. The recommendation is to reaffirm with an action to revise, but at a later time. No action will be taken or archiving of the PTS item until the Standards Efficiency Reviews are complete.			
Deliverable	PR Recommendations			
Deadline	N/A			
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low (was Medium previously)	**Priority (1-Low, 2-Med, 3-High)**	3	**Project has been Re-Baselined? (0-No, 1-Yes)**
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	Jordan Mallory			
PMOS Liaison	Mark Pratt			
Affected Standards	1	FAC-008-3		
Last Updated	10/9/2019			

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	5/10/2017	5/23/2017	5/10/2017	5/23/2017			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	10/30/2017	12/13/2017	10/30/2017	12/13/2017			
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							

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
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							

Project **2017-04** Home

Project Name	Periodic Review of Interchange Scheduling and Coordination Standards			
Status	Other			
Comments	There will be an informational update to the Board in February 2020 that the project will be closed due to the stanard version being superceded.			
Deliverable	PR Recommendations			
Deadline	N/A			
Priority in RSDP, click to see applicable Footnote	**Footnote 9, Low (was Medium previously)**	**Priority (1-Low, 2-Med, 3-High)**	3	**Project has been Re-Baselined? (0-No, 1-Yes)**
P81 Req (2013)	N/A			
Number of Directives		N/A		
No. of Guidances (see Note 2)		N/A		
Directionally consistent with IERP findings (See Note 5)	N/A			
Developer	Laura Anderson			
PMOS Liaison	Charles Yeung			
Affected Standards	4	INT-004, INT-006, INT-009, and INT-010		
Last Updated	10/9/2019			

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	5/2/2017	5/15/2017	5/2/2017	5/15/2017			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	1/10/2018	2/23/2018					
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							

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
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT	2/5/2020	2/7/2020					
Filing - Filing with Regulators							
PT - Post Approval Training							

Project	**2017-05**			**Home**
Project Name	Periodic Review NUC-001-3			
Status	On Hold			
Comments	The review template 45-day posting for preliminary recommendations ended January 29, 2018. There is a meeting scheduled for March 19 to review industry comments and discuss the team's final recommendation. Given the overwhelming industry support for the team's Preliminary Recommendation (Yellow-Revise), they do not anticipate a change in the recommended "color" of the standard. The PRT recommends to reaffirm the standard and has placed the project on hold pending the Standards Efficiency Reivew outcomes.			
Deliverable	PR Recommendations			
Deadline	N/A			
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low (was Medium previously)	**Priority (1-Low, 2-Med, 3-High)**	3	**Project has been Re-Baselined? (0-No. 1-Yes)**
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	Jordan Mallory			
PMOS Liaison	Amy Casuscelli and Colby Bellville			
Affected Standards	1 NUC-001-3			
Last Updated	10/9/2019			

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	5/10/2017	5/23/2017	5/10/2017	5/23/2017			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	12/15/2017	1/29/2018	12/4/2017	1/17/2018	(11)		

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
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	2/5/2020	2/7/2020					
Filing - Filing with Regulators							
PT - Post Approval Training							

Project	**2017-07**			**Home**
Project Name	Stds Alignment with Registration			
Status	Working to Initial Ballot			
Comments	The project has been reactivate and the team plans to meet in mid December 2019. The project is not as simple as just removing a requirement with PSE, IA or LSE. The removal of the requirement may create a gap that would need to be addressed by another functional entity such as Distribution Provider (DP) or Transmission Owner (TO). The team is anticipating going to the SC for approval to do an initial posting and ballot in October or later.			
Deliverable	Standards with PSE, IA, or LSE			
Deadline				
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low	**Priority (1-Low, 2-Med, 3-High)**	3	**Project has been Re-Baselined? (0-No, 1-Yes)**
P81 Req (2013)	N/A			
Number of Directives	N/A			
No. of Guidances (see Note 2)	N/A			
Directionally consistent with IERP findings (See Note 5)	N/A			
Developer	Laura Anderson			
PMOS Liaison	Mike Brytowski			
Affected Standards	18	Standards with PSE, IA, or LSE (CIP-002 through CIP-011, FAC-002, INT-004, IRO-010, MOD-031, MOD-032, NUC-001, TOP-003)		
Last Updated	10/9/2019			

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	8/1/2017	8/14/2017	8/1/2017	8/14/2017			
Nominations - DT	5/1/2018	5/14/2018					
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	8/1/2017	8/30/2017	8/1/2017	8/30/2017			
SP2 - SAR/PR/WP Posting 2	12/11/2017	1/9/2018	12/7/2017	1/6/2018	(4)		

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
CP1 - Comment Period 1	2/1/2018	3/2/2018	2/1/2018	3/2/2018			
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	10/28/2019	12/12/2019	9/17/2018	11/1/2018	(406)		
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/9/2020	1/19/2020	12/4/2018	12/14/2018	(401)		
PTB - Present to BOT	2/5/2020	2/7/2020	2/5/2019	2/8/2019	(365)		
Filing - Filing with Regulators			3/7/2019	3/10/2019			
PT - Post Approval Training							

Project	**2018-04**			**Home**
Project Name	Modifications to PRC-024-2			
Status	Posted			
Comments	The project documents are posted for an additional comment period and ballot through November 4, 2019.			
Deliverable	PRC-024-3			
Deadline	N/A			
Priority in RSDP, click to see applicable Footnote	N/A	**Priority (1-Low, 2-Med, 3-High)**	3	**Project has been Re-Baselined? (0-No, 1-Yes)**
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	Latrice Harkness & Alison Oswald			
PMOS Liaison	Linda Lynch			
Affected Standards	1	PRC-024-2		
Last Updated	10/9/2019			

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	12/19/2018	1/18/2019					
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	12/19/2018	1/18/2019					
SP2 - SAR/PR/WP Posting 2	6/27/2019	7/26/2019					Supl. SAR
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	4/17/2019	5/31/2019	4/17/2019	6/1/2019			
CAB - Com/Add Ballot 2	***9/20/2019***	***11/4/2019***	6/17/2019	8/1/2019	(95)		

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
CAB - Com/Add Ballot 3			8/15/2019	9/29/2019			
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	12/9/2019	12/19/2019	10/14/2019	10/24/2019	(56)		
PTB - Present to BOT	1/1/2020	1/4/2020	11/7/2019	11/10/2019	(55)		
Filing - Filing with Regulators	2/3/2020	2/5/2020	12/10/2019	12/12/2019	(55)		
PT - Post Approval Training							

Project	**2019-01**				**Home**
Project Name	Modifications to TPL-007-3				
Status	Responding to Comment				
Comments	The TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events passed initial ballot and will go to final ballot the week of November 11, 2019.				
Deliverable	TPL-007-4				
Deadline	**6/30/2020**			**8**	**Months to deadline**
Priority in RSDP, click to see applicable Footnote		**Priority (High, Med, Low is 1, 2, 3)**	2	**Project has been Re-Baselined? (0-No, 1-Yes)**	
P81 Req (2013)	N/A				
Number of Directives	1	FERC Order No. 851			
No. of Guidances (see Note 2)		N/A			
Directionally consistent with IERP findings (See Note 5)	N/A				
Developer	Alison Oswald				
PMOS Liaison	Michael Brytowski				
Affected Standards	1	TPL-007-3			
Last Updated	10/9/2019				

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT	2/25/2019	3/26/2019					
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	2/25/2019	3/26/2019					
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	7/26/2019	9/9/2019	7/29/2019	9/12/2019	3		

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
CAB - Com/Add Ballot 2			10/21/2019	12/5/2019			
CAB - Com/Add Ballot 3			1/23/2020	3/8/2020			
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	11/11/2019	11/21/2019	4/20/2020	4/30/2020	161		
PTB - Present to BOT	2/4/2020	2/7/2020	5/13/2020	5/16/2020	99		
Filing - Filing with Regulators	3/8/2020	3/11/2020	6/15/2020	6/18/2020	99		
PT - Post Approval Training							

Project	**2019-02**
Project Name	BES Cyber System Information Access Management
Status	SDT Development
Comments	Supplemental members are planned to be appointed to the team at the October 23, 2019 Standards Committee meeting. The SDT continues to work on revisions to CIP-004 and CIP-011 and made revisions to move Requirements related to BCSI access to CIP-011. This change helps to consolidate all BCSI-related requirements in one CIP Standard. The team is also developing the supporting documentation in preparation for a November posting. A face to face meeting is scheduled for October 16-17, 2019.
Deliverable	TBD
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	
Priority (High, Med, Low is 1, 2, 3)	
Project has been Re-Baselined? (0-No, 1-Yes)	
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	Latrice Harkness
PMOS Liaison	Colby Bellville and Kirk Rosener
Affected Standards	2 CIP-004 and CIP-0011
Last Updated	10/9/2019

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	8/22/2019	9/20/2019					
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	3/28/2019	4/26/2019					
SP2 - SAR/PR/WP Posting 2							

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
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	11/21/2019	1/5/2020	10/24/2019	12/8/2019	(28)		
CAB - Com/Add Ballot 2	2/25/2020	4/10/2020	3/2/2020	4/16/2020	6		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	4/27/2020	5/7/2020	4/27/2020	5/7/2020			
PTB - Present to BOT	5/13/2020	5/16/2020	5/13/2020	5/16/2020			
Filing - Filing with Regulators							
PT - Post Approval Training							

Project	**2019-03**	**Home**
Project Name	Project 2019-03 Cyber Security Supply Chain Risks	
Status	Responding to Comment	
Comments	It is anticipated the Standards Committee will appoint SAR team as the SDT. The SDT will meet in-person on November 19-21, 2019.	
Deliverable	CIP-005-6, CIP-100-3, and CIP-013-1	
Deadline	**12/25/2020**	**14 Months to deadline**
Priority in RSDP, click to see applicable Footnote	**Priority (High, Med, Low is 1, 2, 3)**	**Project has been Re-Baselined? (0-No, 1-Yes)**
P81 Req (2013)	N/A	
Number of Directives	1 This project will address the directives issued by FERC in Order No. 850. This project will also address NERC staff recommendation from the Supply Chain Report.	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Alison Oswald	
PMOS Liaison	Linda Lynch (Primary) and Kirk Rosener (Secondary)	
Affected Standards	2 CIP-005-6, CIP-010-3, and CIP-013-1	
Last Updated	10/9/2019	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT	7/2/2019	8/1/2019					
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	7/2/2019	8/1/2019					
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							

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
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							

Project	**2019-04**	**Home**
Project Name	Modifications to PRC-005-6	
Status	Nominations	
Comments	The Standards Committee accepted the Standard Authorization Request (SAR) on July 24, 2019 and authorized the SAR for a 30-day formal posting and comment period. Nominations for the Standard Authorization Request drafting team members ended August 28, 2019 along with the formal comment period for the SAR. NERC staff plan to seek an additional solicitation for team members.	
Deliverable	PRC-005	
Deadline		
Priority in RSDP, click to see applicable Footnote		**Priority (High, Med, Low is 1, 2, 3)** / **Project has been Re-Baselined? (0-No, 1-Yes)**
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Laura Anderson	
PMOS Liaison	Mark Pratt and Linda Lynch	
Affected Standards	1 PRC-005-6	
Last Updated	10/9/2019	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT	7/30/2019	8/28/2019					
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	7/30/2019	8/28/2019					
SP2 - SAR/PR/WP Posting 2							

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
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							

Project	**2019-05**
Project Name	Modifications to PER-003
Status	SDT Development
Comments	The SAR comment period ended August 30, 2019. NERC is currently vetting nominations for the SAR drafting team to present to the Standards Committee on October 23, 2019.
Deliverable	PER-003
Deadline	
Priority in RSDP, click to see applicable Footnote	
Priority (1-Low, 2-Med, 3-High)	
Project has been Re-Baselined? (0-No, 1-Yes)	
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	Alison Oswald
PMOS Liaison	Colby Bellville and Kirk Rosener
Affected Standards	1 PER-003
Last Updated	10/9/2019

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	8/1/2019	8/30/2019					
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							

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
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							

Project	**2019-06**	**Home**
Project Name	Cold Weather	
Status	Posted	
Comments	A formal comment period for the Project 2019-06 Cold Weather Standard Authorization Request (SAR) is open through 8 p.m. Eastern, Tuesday, November 5, 2019. Additionally, nominations are being sought for SAR drafting team members through 8 p.m. Eastern, Tuesday November 5, 2019. The Standards Committee is expected to appoint members to the team December 2019. Nominees will be notified shortly after they have been selected.	
Deliverable	TBD	
Deadline		
Priority in RSDP, click to see applicable Footnote	**Priority (1-Low, 2-Med, 3-High)**	**Project has been Re-Baselined? (0-No, 1-Yes)**
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	Jordan Mallory	
PMOS Liaison	TBD	
Affected Standards	To be determined by the team	
Last Updated	10/9/2019	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	***10/4/2019***	***11/5/2019***					
SP2 - SAR/PR/WP Posting 2							

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
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							

Home

FOOTNOTES

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

Home

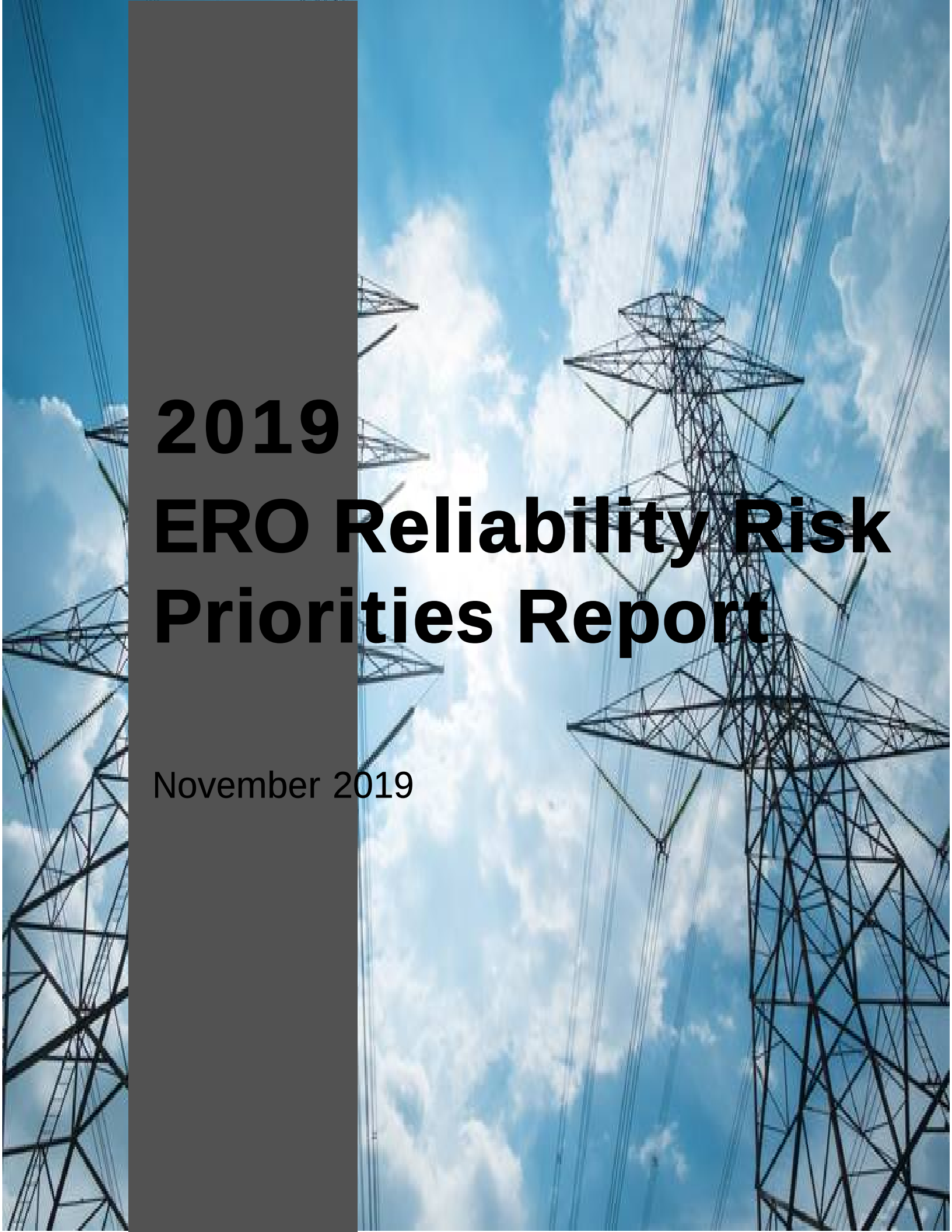
FOOTNOTES

No.	Description
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
Note 10	2019-2021 RSDP (Draft)

RSC Meeting #19-4, Agenda Item 4.0 Open Action Items

Item	Description	Owner	Due	Status
4.1	Mike Jones, Quintin and Herb Schrayshuen volunteered to assist Guy Zito and Ruida Shu on reviewing the NPCC RSPM Guy Zito and Ruida Shu will review the draft redline from the subgroup.	Guy Zito Ruida Shu	By end of 2019	Pending
4.2	RSC to incorporate process into the Directory Manual.	RSC	By end of 2019	Pending
4.3	RSC to review NPCC DER Guidance Document	RSC	By end of 2019	Pending

DRAFT



2019 ERO Reliability Risk Priorities Report

November 2019

Table of Contents

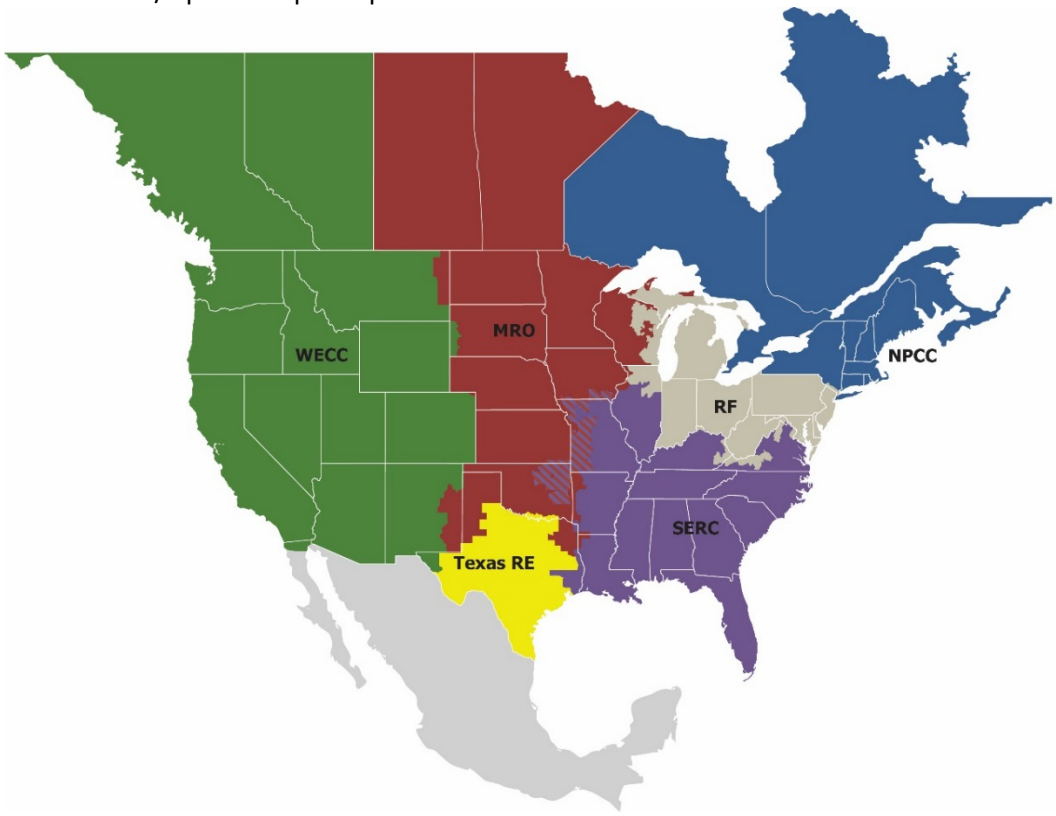
Preface iii
Executive Summary 5
Common Themes and Emerging Trends 6
Background and Introduction 8
Background 8
Inputs to the Risk Profiles 8
Prioritization of Inherent Priority Risks 12
Risk Groupings 12
Risk Profiles 14
Risk Profile #1: Grid Transformation 14
Risk Profile #2: Extreme Natural Events 18
Risk Profile #3: Security Vulnerabilities 21
Risk Profile #4: Critical Infrastructure Interdependencies 24

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (RE), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

The Reliability Issues Steering Committee (RISC) is an advisory committee to the NERC Board of Trustees (Board). The RISC provides key insights, priorities, and high-level leadership for issues of strategic importance to BPS reliability. The RISC advises the Board, NERC committees, NERC staff, regulators, REs, and industry stakeholders to establish a common understanding of the scope, priority, and goals for the development of solutions to address emerging reliability issues. The RISC provides guidance to the ERO Enterprise[1] and the industry to effectively focus resources on the critical issues to improve the reliability of the BPS.

This ERO Reliability Risk Priorities report (RISC report) presents the results of the RISC's continued work to strategically define and prioritize risks to the reliable operation of the BPS and thereby provide recommendations to the Board regarding the approach that NERC, the ERO, and industry should take to enhance reliability and manage those risks.

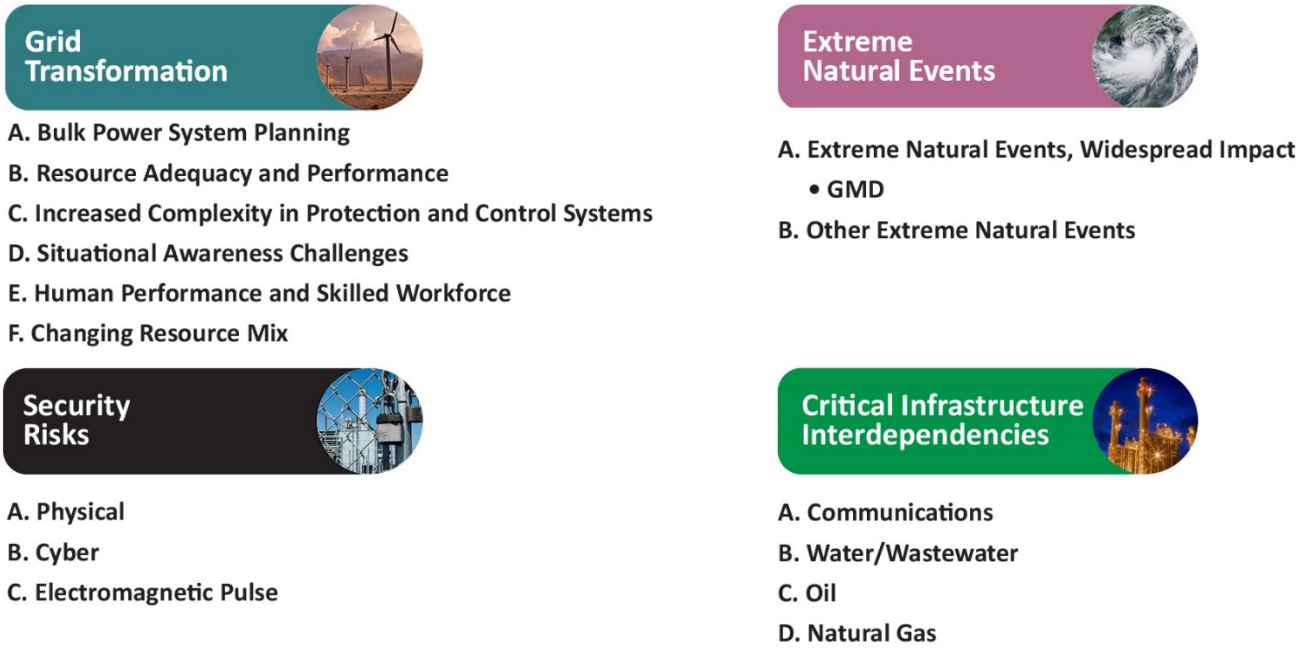
[1] ERO Enterprise is interpreted to mean NERC, the Regional Entities, and the technical committees of NERC.

Executive Summary

The primary objective of the 2019 ERO Risk Priorities Report is to highlight risks that merit attention and recommend actions that align with those risks. This report differs from other ERO reports in that it is a forward-looking view of the BPS. For example, this is in contrast to the *State of Reliability* report, which reviews data from previous years to draw objective conclusions about emerging risks and monitors their mitigation.

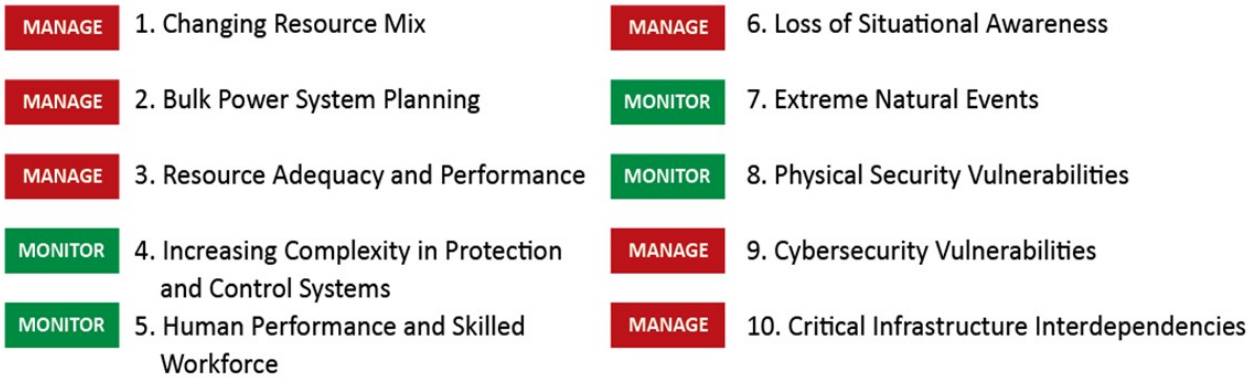
On September 13, 2019, an initial draft of the report was posted for Stakeholder comments.

This report reflects the collective opinion of the RISC membership regarding the priorities. The RISC reviewed and assembled information from ERO Enterprise stakeholders, policymakers,[2] and focused subgroup work to develop an initial composite set of risk profiles. Further review and consolidation resulted in four high level risks: 1) Grid Transformation, 2) Extreme Natural Events, 3) Security Vulnerabilities, and 4) Critical Infrastructure Interdependencies. Below illustrates the encapsulation of the identified risks which are further detailed in the Risk Profiles section.



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

For the 2019 report, the RISC also significantly reduced the number of recommendations by consolidating overlapping recommendations and removing recommendations that reflect activities, which, while important, are already well underway and monitored as part of NERC's Long-Term Strategic Plan and applicable NERC committee plans. The graphic below depicts the classification for each of the identified risks:



The Risk Profiles section of this report provides Statement of Risk, Descriptors of Risk, and Recommendations for Mitigating the Risk. Through the risk profiles, the RISC recommends actionable mitigating activities, which enable the ERO Enterprise and industry to use the composite risk profiles and the risk map for baseline and recurring evaluation of reliability risks.

When possible, the RISC also identified the group or organization that it believes should lead the mitigating action. However, some recommendations do not present a clear owner or responsible party. In these cases, the recommendation is presented as a more generalized action item that can apply to numerous entities, including policymakers, industry, and the various organizations within the ERO Enterprise. The RISC did not assess resource needs for the mitigating actions which will be addressed with industry during the annual ERO Enterprise Business Plan and Budget activities.

Additionally, the committee evaluated risks based on impact to the BPS regardless of the source or location of the risk. To evaluate key risks to the system, the RISC recognized emerging issues emanating from different areas of the grid (e.g., resources such as distributed energy resources (DER) that may not be located or directly connected to the BPS). Operators and planners of the BPS are aware of the need to have a wide-area view of changes to the system to provide an understanding of external conditions that can affect them. Therefore, the profiles identify several risks where the BPS can be impacted at interfaces (e.g., customers distributed resources, resources located on the electric distribution system, gas delivery system, telecom system, water system, etc.). RISC determined it is important to illuminate external factors that increase BPS risk and offered recommendations to address those risks.

Common Themes and Emerging Trends

For those risks that the committee recommends active monitoring, it is important to note that a convergence of centralized themes and emerging trends is present. These themes and trends underscore not only the increasing interdependency between identified BPS risks but also an increase in potential magnitude of emerging risks. Common themes and emerging trends are indicated below:

- Interdependencies between industries and fuel types
- Increased security risks (both cyber and physical)
- The increase in natural gas and renewable generation coupled with the decline in nuclear and coal-fired generation

- The importance of emerging technologies and how to best incorporate those into a reliable and secure BPS
- Significant changes to the grid require new models and tools for reliable integration
- Development of the credible and centralize data sharing, and the right tools to proactively analyze system conditions is becoming more critical

Background and Introduction

Background

This report documents the results of the RISC's continued work to identify key risks to the reliable operation of the BPS and provide recommendations to mitigate those risks. This report includes recommendations regarding relative priorities to further assist the Board and NERC management as well as industry and its stakeholders.

The RISC's efforts are both responsive and in support of the Board's resolutions in connection with the initial 2013 RISC recommendations,[3] which directs continued work by the RISC to define and prioritize risks as well as to develop mitigating activities and identify accountable parties for those risks ensuring reduction.

There are important linkages between the risk priorities and the recommended actions for the ERO Enterprise and industry. While the risk profile recommendations in this report are presented individually, there are interdependencies between many of the risks that present unique challenges to the electric industry. These interdependencies have been acknowledged in the report. Further, many of these risks have been long recognized with commensurate NERC and industry monitoring for proper mitigation, whereas others are newly emerging requiring active management with a more aggressive immediate approach necessary for effective foresight and mitigation. The RISC acknowledges and appreciates the increased reliance of the Board and ERO Enterprise leadership on the results of RISC's activities as an input for the ERO Enterprise's Long-Term Strategic Plan and Business Plan and Budget. The RISC did not assess the resource impacts of the recommendations which will be addressed with industry during the annual ERO Enterprise Business Plan and Budget activities.

The RISC participants include representatives from the NERC committees, the Member Representatives Committee (MRC), and "at large" industry executives. The observations, findings, and guidance presented in this report include input from industry forums, trade associations, and other industry groups through multiple channels. The RISC also received feedback through an Emerging Risks Survey, which garnered over 150 responses.

This report relies on and extends the comprehensive initial assessment and corresponding recommendations to the Board made in February 2018, which have been updated and refined. This report and recommendations also reflect discussions with representatives from the NERC committees, the discussion with leaders at the NERC Reliability Leadership Summit, and the many technical reports and assessments conducted by NERC and industry.

Inputs to the Risk Profiles

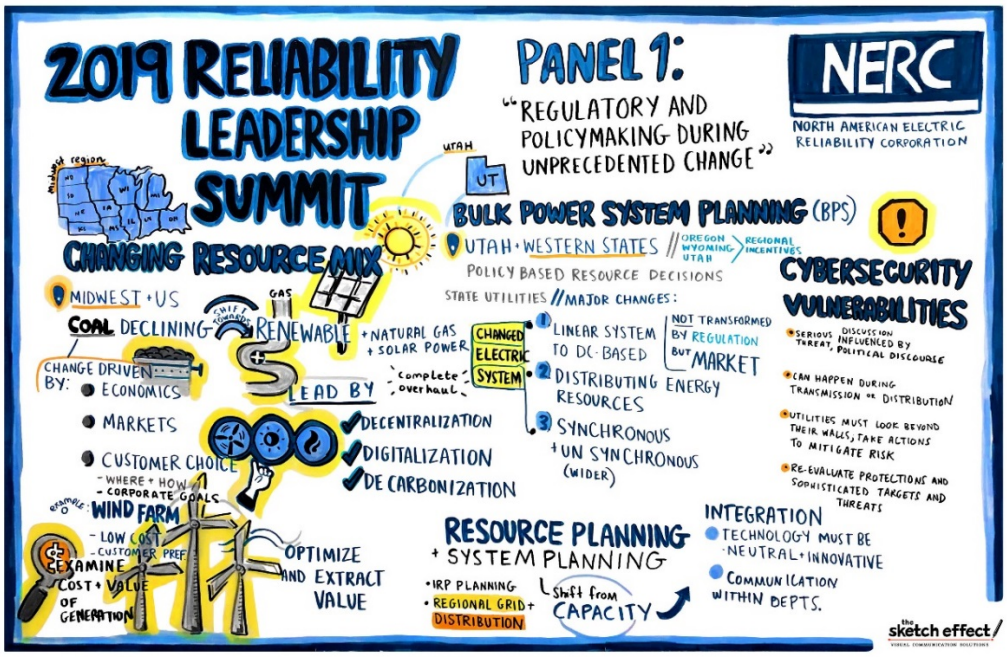
Reliability Leadership Summit

On March 14, 2019, NERC and the RISC hosted a Reliability Leadership Summit (Summit) with leaders of the reliability community, including top industry executives, state and federal regulators, and NERC and Regional Entity senior leadership. The summit focused on three specific areas: regulatory and policymaking during unprecedented change, identifying and mitigating significant existing and emerging landscape of risks to reliability, and providing assurance for the availability of adequate fuel delivery to satisfy energy needs. Open discussion at the end of the summit was held to address these and any other risks that required deeper investigation. Below are the pictograph summaries of each of these sessions.

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

Reliability Leadership Summit

Regulatory and Policymaking During Unprecedented Change



NERC - RELIABILITY LEADERSHIP SUMMIT
MARCH 2019 | WASHINGTON, DC

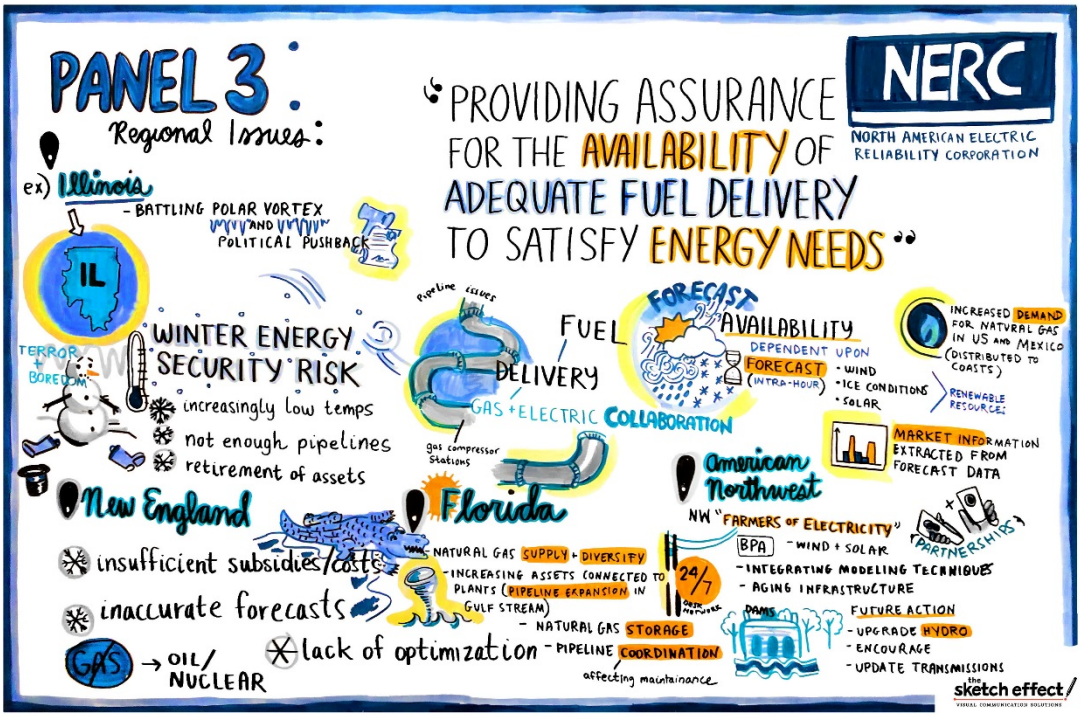
Instagram & Twitter: @TheSketchEffect
Facebook.com/TheSketchEffect

Identifying and Mitigating Significant Existing and Emerging Landscape of Risks to Reliability

NERC - RELIABILITY LEADERSHIP SUMMIT
MARCH 2019 | WASHINGTON, DC

Instagram & Twitter: @TheSketchEffect
Facebook.com/TheSketchEffect

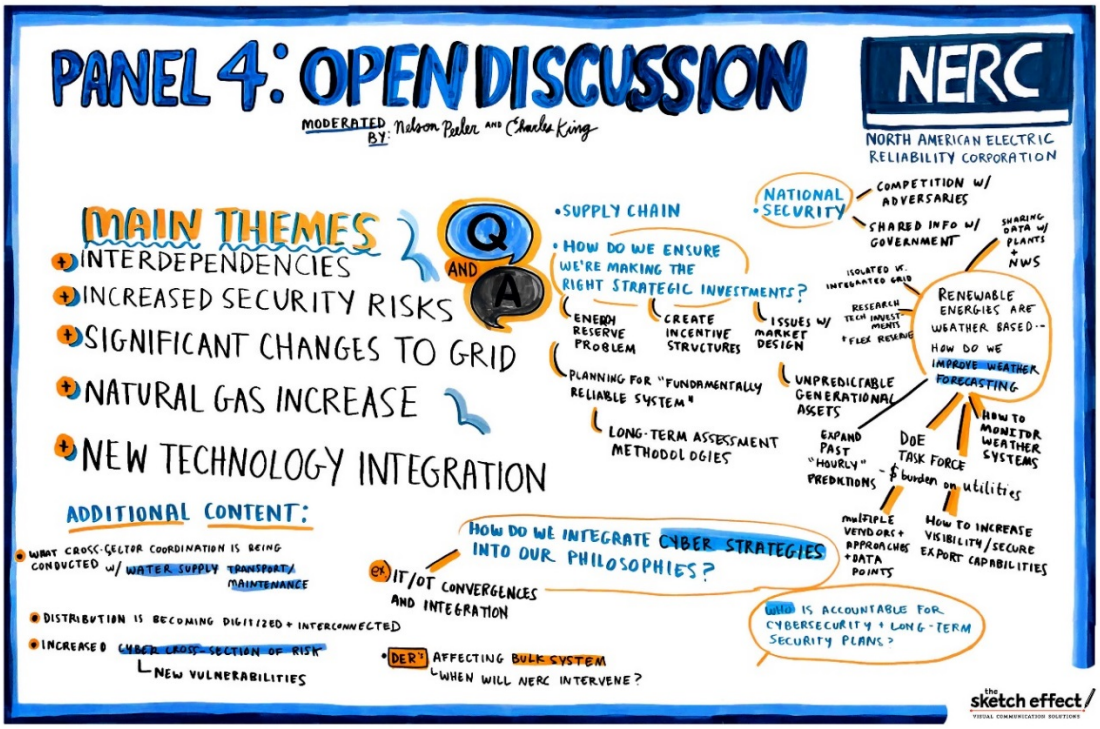
Providing Assurance for the Availability of Adequate Fuel Delivery to Satisfy Energy Needs



NERC - RELIABILITY LEADERSHIP SUMMIT
MARCH 2019 | WASHINGTON, DC

Instagram & Twitter: @TheSketchEffect
Facebook.com/TheSketchEffect

Open Discussion



NERC - RELIABILITY LEADERSHIP SUMMIT
MARCH 2019 | WASHINGTON, DC

Instagram & Twitter: @TheSketchEffect
Facebook.com/TheSketchEffect

The panel discussions underscored the importance of conducting cross-sector coordination with other industries. The potential impact on reliability from the accelerating proliferation of distributed energy resources (DERs) was discussed, along with potential NERC efforts to assess the effects of DER on the reliable operation of the BPS.

Recognizing that the performance of renewable energy resources is affected by weather, the discussions reiterated the importance of improving weather forecasting to mitigate risks associated with its uncertainty. With large increases in renewable resources and gas-fired units, continued retirements of coal and nuclear units is expected. All resources must be integrated reliably and ensure that sufficient levels of grid essential reliability service (ERS) are maintained.

While planning for a fundamentally reliable system and recognizing the impacts of grid transformation, it is important to continue to evaluate reserve margins and the appropriate mechanisms for establishing adequate reserve margins, particularly given the changing dynamics of the BPS. The operation of the grid and the relationship between Generator Operators and Balancing Authorities has changed due to proliferation of distributed energy resources and the creation of larger Balancing Authorities operated by centralized RTO markets.

Lastly, the need for higher levels of cyber security will continue to create additional intricacies to BPS reliability. It is important to understand which organizations are accountable for cyber security and long-term security plans. Information technology and operational technology convergences should be recognized and adequate levels of cyber security should be planned for prospectively. Cross-sector communication will be critical to effective management of cyber risks and it will be important to standards to transcend industries in order to ensure effective implementation and coherence across critical industries.

Prioritization of Inherent Priority Risks

Risk Groupings

This year is transitional for the RISC Report and includes industry input on each risk profile, as well as a new format. In 2018, input was requested from industry for each of the prior year risk profiles. Unlike previous RISC reports where the risk likelihood and impact was derived from the expertise of the RISC Committee, the 2019 risk mappings of impact and likelihood were derived using a comprehensive survey provided to industry leaders across the ERO footprint. The survey results have been used to establish a 2020 base line of impacts and likelihood that can be used to trend and benchmark against subsequent RISC reports and analyses. Survey results provided the RISC with a two-fold benefit: 1) a prioritization of the existing risk profiles, and 2) the ability to consolidate the profiles from nine[4] to four. The 2018 survey did not provide an overarching data collection for each stated Risk Profile. The survey data is considered relevant and has been reviewed with the expertise and judgement of the RISC members.

The prioritization by industry did align with prior year's Heat Map placement of each Risk Profile "bubble". The data now provides a baseline capability from which the RISC can determine over time how each risk is viewed by industry through its evolution and risk profile lifecycle. In addition, survey data provided quantitative information for the RISC members to discuss prior to Heat Map finalization. Similar to prior years, the Heat Map is formatted based on an X-Y axis: X representing the potential likelihood or probability of the risk coming to fruition, and Y representing the perceived impact. Risk Profile placement is based on 2019 data where 0 = Minimal risk/Minimal impact, and 5 = Severe risk/Severe impact.

Consolidation of prior year's risk profiles from nine to four simplifies high-level discussions on risk identification and phased mitigation or remediation processes.

The Heat Map tracks the risks so industry can consider potential impacts within their organization. Figure 2 shows each of the identified individual inherent risk profiles mapped against likelihood and impact scales. The Heat Map illustrates RISC's assessment of how the inherent risks of the profiles have changed, if any, from the previous report. Extreme Natural Events and Human Performance and Skilled Workforce had the most significant change (identified in **red** on the heat map), while all other risks remained in the same general location as the previous report. The orange color on the individual risk heat maps represents the high-level risk profile they are associated with.

[4] Critical Infrastructure Interdependencies was added as the tenth Risk Profile mid-year in 2018 while reformatting the Report and developing the Industry Risk Profile Survey.

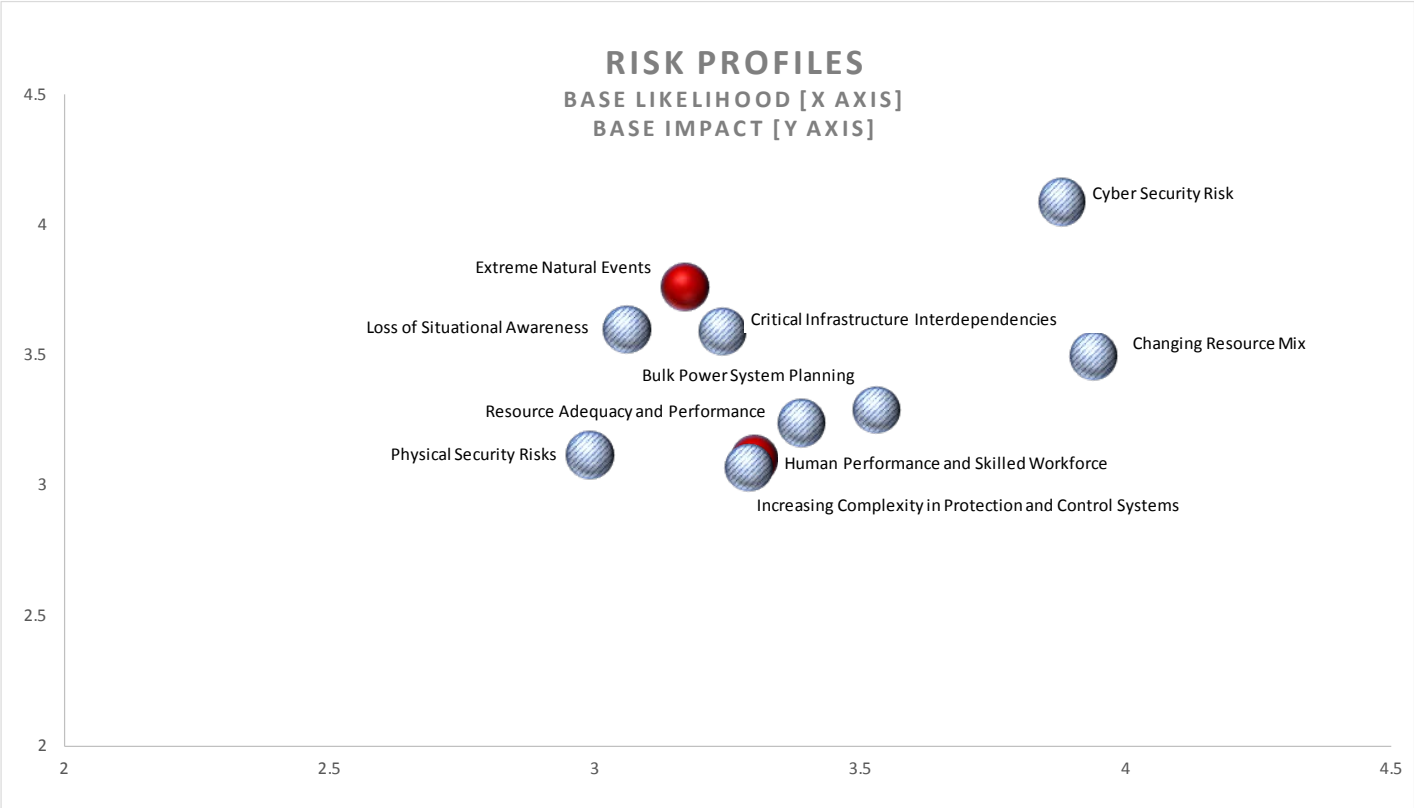


Figure 2 Risk Profiles

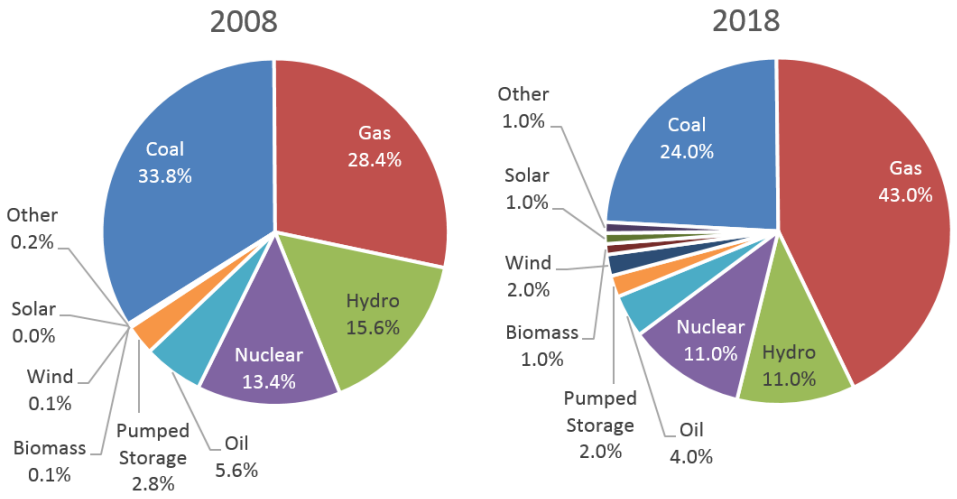
Risk Profiles

Risk Profile #1: Grid Transformation

The transformation of generating resources and fuel sources, along with changes in load characteristics is creating new reliability risks, from long and short-term planning to real-time operations.

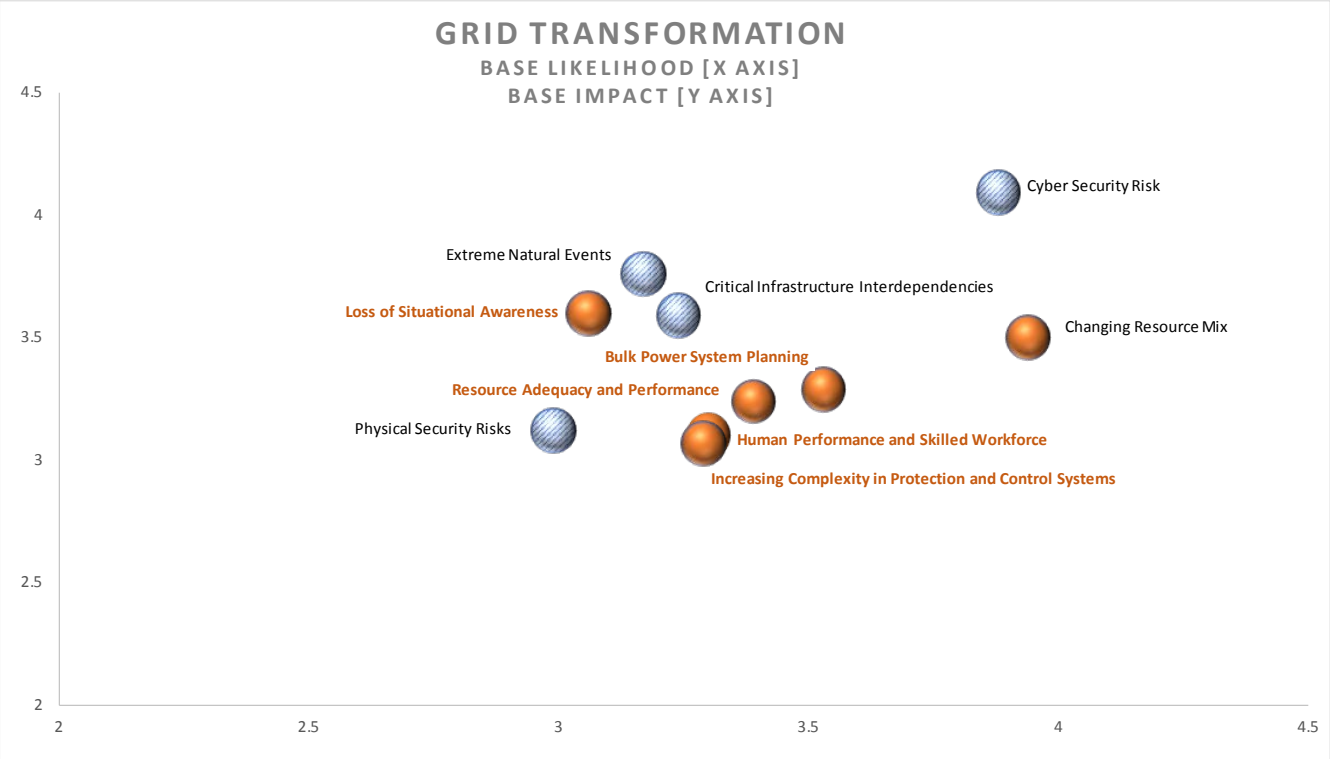
Statement of the Risk

Public inputs, along with the influence of regulatory and socio-economic policies, are continuing to drive a significant evolution in the mix of power resources. The shift away from conventional synchronous central-station generators toward a new mix of resources continue to challenge generation and grid planners and operators. This new paradigm of the resource mix includes natural-gas fired generation, unprecedented proportions of non-synchronous resources including renewables and battery storage, as well as demand response, smart- and micro-grids, and other emerging technologies. Collectively, the new resources are more susceptible to energy sufficiency issues through common mode contingencies in fuel supply, whether the fuel is gas, or inverter-based. Looking forward, consumers' desire to decarbonize, individual states' legislative and regulatory initiatives, expected lower production costs of new resources, and the aging of existing generation infrastructure all will alter the nature and dispatch of generation thus leading to further resource and grid transformation.



This transformation presents a number of potential challenges and opportunities when it comes to reliability of the bulk power system (BPS) as detailed in the descriptors of the risk below.

Risk Mapping



Descriptors of the Risk

- **Changing Resource Mix; Bulk Power System Planning and; Resource Adequacy and Performance**
  - **Potential impact on Essential Reliability Services** — Transformation of the resource mix can alter the provision of and need for Essential Reliability Services (ERS) and other ancillary services needed for BPS reliability and system operations, such as voltage control and reactive support, frequency response, and ramping/balancing. Restoration services, such as blackstart capabilities and procedures, could be affected as well.
  - **Technology with Different Design and Performance Characteristics** — The continued integration of large amounts of new resource technologies, including but not limited to DER, grid-connected inverter-based resources and energy storage, could lead to inaccurate forecasting of anticipated demand. Further, this integration can also result in other planning and operational challenges, if these resource additions are not observable or predictable, or are otherwise not taken into account. The dynamic and transient performance and response of these technologies also brings new challenges.
  - **New Data and Information Requirements** — The need for data and information about new and changing resource characteristics must be incorporated into the long-term planning, operational planning, and operating time horizons. Some of this new information will be from non-traditional sources, e.g., breakout of netted DER aggregations and inverter operating parameters, which in itself may present challenges to those responsible for incorporating the information into models representing future conditions.
  - **Battery and Storage Technologies** — Storage capabilities and uses will likely transform both distributed and bulk system operations. Whether in combination with renewables or conventional resources, and whether connected to distribution systems or the bulk power system, storage and hybrid technologies

will further magnify the pace of innovation and the evolution of resource capabilities during both steady state and transient conditions.

- **Fuel Supply Considerations** — Fuel sourcing and disruption capabilities, such as from weather events and other nature-based extreme conditions, are driving new scenarios and case studies and broadening the range of dependencies for reliability planning and operations. Fuel constraints and environmental limitations might not be reflected in resource adequacy assessments.
- **Resource Adequacy Guidelines Consideration** – In addition to fuel sourcing, other elements of resource adequacy such as transmission development, pipeline construction, and environmental permitting may need much more lead-time in order to assure future reliability and resource adequacy of the system.
- **Ensuring Sufficient Flexible Resources to Meet Demand** – With the volume of wind and solar resources expected and their characteristic fuel-driven commitment and dispatch capabilities, as well as the characteristics of other resources that may constrain their near-term ability to respond, sufficient flexible resources will be needed to meet demand when the less flexible resources are unavailable. The flexible resources will need to be dispatchable within the forecasting period of the less flexible resources becoming unavailable.
- **Coordination of behind-the-meter DERs with the BPS** – Distributed generation, storage and other DER technologies currently follow local interconnection requirements and operational protocols posing potential challenges to the BPS from a planning and forecasting perspective.

- **Human Performance and Skilled Workforce -** The BPS is becoming more complex, and as the industry faces turnover in technical expertise, it will have difficulty staffing and maintaining necessary skilled workers.
- **Loss of Situational Awareness:** Loss or degradation of Situational Awareness poses BPS challenges as it affects the ability of personnel or automatic control systems to perceive and anticipate degradation of system reliability and take pre-emptive action.
- **Control and Protection Systems Complexity** — The interaction and performance of control systems during transient events, including the control systems in remedial action schemes (RAS) and other protection systems, must be understood to prevent new common-mode failures that may not have been anticipated (e.g., the inverter performance as demonstrated during the Blue Cut fire and related events, misoperation of RAS logic and control systems, interdependencies of RAS operations in sequence and follow through, etc.).

Recommendations for Mitigating the Risk

As a result of this complex set of factors, the traditional methods of assessing resource adequacy (by focusing primarily on generating capacity, transmission and pipeline capacity, and fuel availability at traditional peak load times) may not accurately or fully reflect the ability of the new resource mix to supply energy and reserves for all operating conditions. Historic methods of assessing and allocating ancillary services—such as regulation, ramping, frequency response, and voltage support during transient, recovery and follow through—may no longer ensure that sufficient ERS and contingency reserves are available at all times during real time, next hour and next day operations. Balancing and ramping concerns, which up to now have been largely confined to limited locations, will likely expand regionally as solar and wind generation continues to grow and provides a larger portion of the energy mix. Such resources provide challenges in counting as available capacity in traditional integrated resource planning to assure reliability of the BPS in near-term to long-term planning horizons.

The combination of these many factors related to resource and grid transformation, offering both challenges and opportunities as a result of the transformation, calls for a planned set of NERC activities as described in the following action plan.

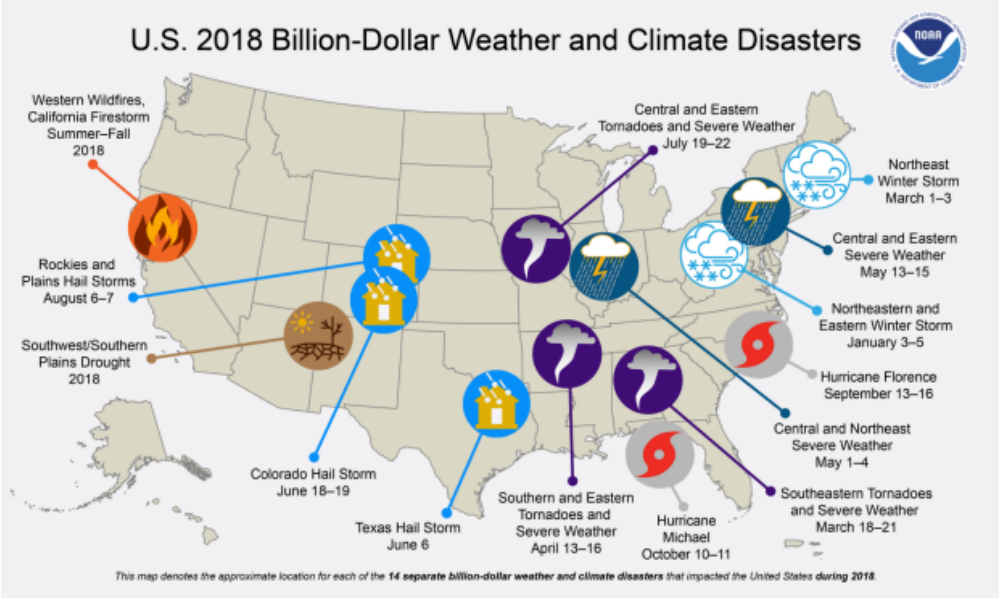
Resource and grid transformation will require new and updated tools, methods, and strategies that are used in planning, modeling, and operating the BPS. In order to best achieve those goals, we encourage the following actions:

1. **Update Data, Modeling and Assessment Requirements to Ensure Valid and Accurate Results Given Resource and Grid Transformation - Ongoing Effort:** The ERO's Committees should identify the information and modeling capabilities needed to ensure the efficacy of assessments, taking into consideration the complex and interrelated aspects of the ongoing transformation. The ERO should also pay close attention on settings of controllable devices and power electronics installed to stabilize the system. The risk of cascading continues to increase and more remedial action schemes with its complexity are added to BPS system.
2. **NERC should work with its technical committees to establish a study group to assess battery storage and their implications on reliability.** Work with organizations (IEEE, EPRI, NATF, NAGF) to establish clear interconnection protocols on all facilities (DERs, Storage, etc.) to BPS and identify the roles and responsibilities of the BES, BPS, and distribution operations.
3. **Improve Inverter-Based Resource BPS Interconnection and Operation, and Stay Abreast of New Technologies such as Storage/Hybrid Resources:** The ERO Enterprise should continue their effort to address the recommendations of the Inverter-Based Resource Performance Task Force (IRPTF).
4. **Ensure Sufficient Operating Flexibility at all Stages of Resource and Grid Transformation**: System Operators and Planners should ensure sufficient flexible ramping/balancing capacity is available as a tool to meet needs of changing patterns of variability and new characteristics of system performance.

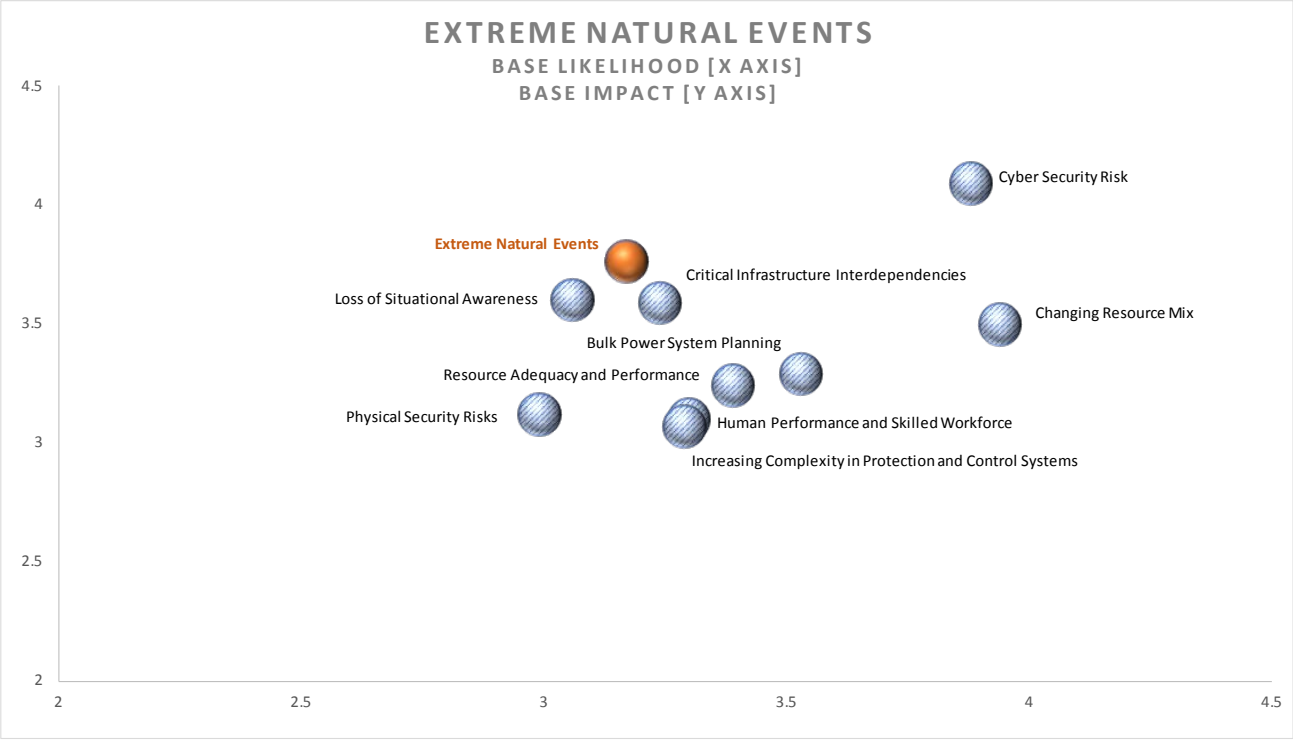
Risk Profile #2: Extreme Natural Events

Statement of the Risk

Extreme natural events (storms, wildfire, etc.) cause a significant proportion of major BPS impacts. For example, NERC's "2019 State of Reliability" report[5] noted weather was responsible for all category 3, 4, and 5 BPS events across the Electric Reliability Organization Enterprise's footprint in 2018. Extreme natural events tend to be regional in nature. Natural events may affect BES equipment, resources, or infrastructure required to operate the BES. Certain events are unique to region(s), which they impact, while others may occur in any region of the BPS. Each type of event brings unique challenges from a supply sufficiency, spare-parts availability, delivery, and restoration perspective. Preparation and proactive planning of procedures and protocols are critical for utilities to assess and determine appropriate steps for both reliability and resiliency.



Risk Mapping



[5] https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2019.pdf

Descriptors of the Risk

Various North American regions routinely incur severe natural events, such as hurricanes in Florida and extreme cold in the north. While the risk of these events in those regions is high, the relative impact on the bulk power system is low. For instance:

- **Hurricanes** can cause widespread destruction to BES equipment, degradation of communication capabilities, loss of load, and damage to generation resources. Recovery and restoration efforts can be hampered due to the size or scope of the storm and damage to interdependent infrastructure.
- **Tornados/Derecho** can cause localized destruction to BES equipment, local degradation of communication capabilities, loss of load, and damage to generation resources. Recovery and restoration efforts can be hampered due to local damage to interdependent infrastructure
- **Extreme Heat and Drought** can cause higher than anticipated demand, overloading and failure of BES equipment, and degradation of resource availability. There can be limited water available for operating hydroelectric generation or reduced cooling water capacity. Drought can also be a precursor to wild fire risk as described below.
- **Wild Fires** can be a direct threat to BES equipment. Pre-emptive actions must be taken to de-energize equipment without causing additional cascading effects in areas where wild fire risk is significant.
- **Flooding** can occur in any area and in any season of the year. The impacts from flooding include mechanical damage to BES equipment, degradation of clearances, fuel infrastructure, personnel access, and communications capabilities.
- **Extreme Cold Weather (Polar Vortices)** can cause higher than anticipated demand, overloading and stress failure of BES equipment, and degradation of resource availability via mechanical failure or fuel supply interruption.

Other types of severe natural events, though less likely, could have a higher impact given the potentially broader geographic footprint. For instance:

- **Earthquakes** are possible in many areas of the United States and Canada. Depending on the scope and magnitude of the event, mechanical damage may occur to BES facilities and interdependent infrastructure—communications, fuel, transportation, etc. The duration to recover from earthquakes could be long and further assessment and coordination is required among utilities and the ERO Enterprise.
- **Geomagnetic Disturbances** can induce harmonic currents in BES circuits and equipment. The impacts of these induced currents may include overheating of transformers, relay misoperations, and increased reactive demand or damage to reactive resources. GMD events can also affect communications capabilities, fuel delivery and GPS systems.

Recommendations for Mitigating the Risk

Extreme Natural Events and their potential impacts on BPS reliability should be monitored and addressed to maintain reliability and improve resiliency. Based on uncertainties predicting some events, it is important for operations and planning personnel to remain vigilant and prepare for high-risk seasons by learning from prior events, practicing recovery efforts, and anticipating impacts of an event to critical infrastructure needed to operate or restore the BES.

In order to best achieve those goals, we encourage the following actions:

1. **Special assessments of extreme natural event impacts including capturing lessons learned, creating simulation models & establishment of protocols and procedures for system recovery and resiliency:** The ERO Enterprise should conduct detailed special assessments of extreme natural event impacts by geographical areas that integrate:

- Infrastructure interdependencies (e.g. telecommunications, water supply, generator fuel supply)
- Analytic data and insights regarding resilience under severe weather conditions.

Based on those assessments, the ERO Enterprise should develop detailed special assessments on possible mitigation plans and provide a roadmap for its implementations. The road map should include specific protocols and procedures for system restoration and system resiliency, should address the compliance requirements until system is considered normal operations.

2. **Development of Tools for BPS Resiliency** – The DOE is in process of developing appropriate tools for BPS resiliency and NERC, ERO, NATF and NAGF should work with DOE in assessing the tools and develop specific guidelines and procedures for industry to follow.
3. **Understanding of GMD events on BPS** – The ERO Enterprise should continue working with EPRI and others to conduct research and development to further understand impacts from geomagnetically induced current on BES facilities to support enhancements to models and standards and to facilitate preparedness consider preparing sensitivity analyses to simulate the impacts in a planning area. The ERO Enterprise should assist the industry to implement the necessary protocols and mitigation plans to reduce the risk in maintain reliability and security for the BPS.

Risk Profile #3: Security Vulnerabilities

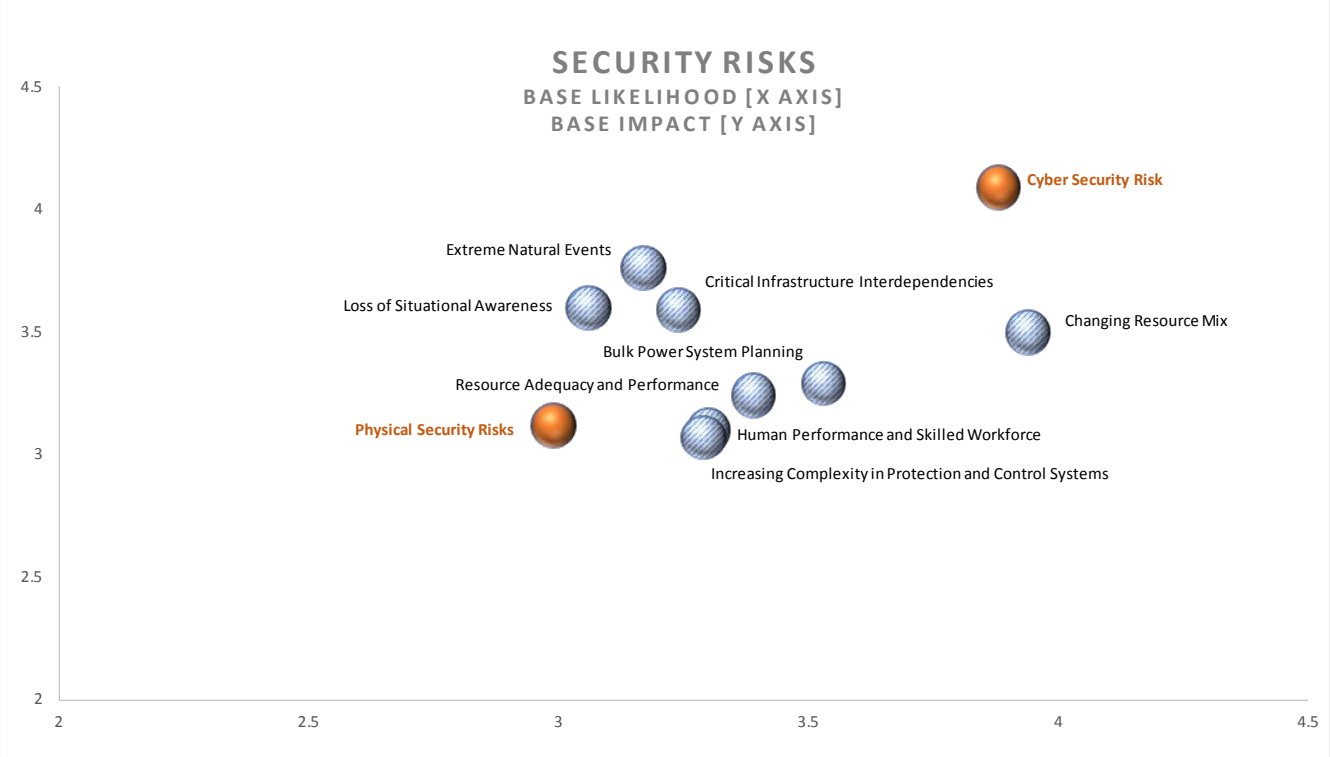
Statement of the Risk

Operational security is an essential component of a highly reliable bulk power system. Cyber and physical security are interdependent aspects, as exploitation of either physical or cyber security vulnerabilities could be used to compromise the other dimension. Resulting impacts could cause asset damage or loss of functionality and situational awareness needed to reliably operate or restore the bulk power system (BPS). Exploitation could occur directly against equipment used to monitor, protect, and control the BPS or indirectly through supporting systems, such as voice communications or interdependent critical infrastructure sectors[6] and subsectors, such as water supply and natural gas used for electrical power generation. A coordinated cyber and physical attack scenario, potentially targeted to occur simultaneously with an extreme natural event, could further impact reliability and/or complicate recovery activities. A man-made electromagnetic pulse (EMP) event targeted at the BPS may impact operations and result in damaged equipment that may require an extended period of time to replace.

The volume, frequency, and sophistication of cyber exploits is increasing and could potentially disrupt a broad (e.g., interconnection-wide) footprint. Significant physical security events have been rare and the impact is likely to be more geographically constrained. EMP events are far less likely to occur, but may carry a highly consequential security risk.

[6] https://www.dhs.gov/cisa/critical-infrastructure-sectors

Risk Mapping



Descriptors of the Risk

1. **Physical Security Vulnerabilities:** The nature and impact of physical vulnerabilities are better understood than other security risks (e.g., cyber or EMP). Actual instances of significant physical attacks have been rare and such attacks are likely to be more localized geographically. There is modest, ongoing evolution of the physical security vulnerability via drones. The largest risk considerations are considered to be the co-dependence with cyber security (e.g. computer controls for physical access) and, the prospective impact of replacing long lead-time equipment (e.g. large power transformers) damaged during an attack.

2. **Cyber Security Vulnerabilities:** Exploitation of cyber security vulnerabilities could arise from a variety of external and/or internal sources. Additionally, the operational and technological environment of the electrical grid is evolving significantly and rapidly, potentially increasing the potential cyberattack-surface.[7] Sources of potential exploitation include increasingly sophisticated attacks by nation states, terrorist, and criminal organizations. Vulnerability to such exploits are exacerbated by insider threats, poor cyber hygiene, supply-chain considerations, and dramatic transformation of the grid's operational and technological environment. These transformative changes include convergence of information and operational technology (IT/OT), reliance on cloud-based technology, and potential workforce knowledge gaps.

3. **Electromagnetic Pulse Vulnerabilities:** An electromagnetic pulse (EMP) is a short-duration, high-energy burst that may be disruptive or damaging to electronic equipment. For security purposes, EMP refers to man-made sources. A high-altitude EMP (HEMP) is an electromagnetic pulse stimulated by a nuclear blast in the atmosphere and such action would likely be initiated by a nation-state and thus have clear national security implications. HEMP concerns include the large geographic footprint susceptible to the pulse, range of electric grid equipment at risk (generation, transmission, distribution, and load), lack of definitive forewarning.

[7] Placeholder for definition or whatever you wanted to do here

Smaller (handheld devices) are relatively limited in potential impact and can be considered analogous to a physical attack.

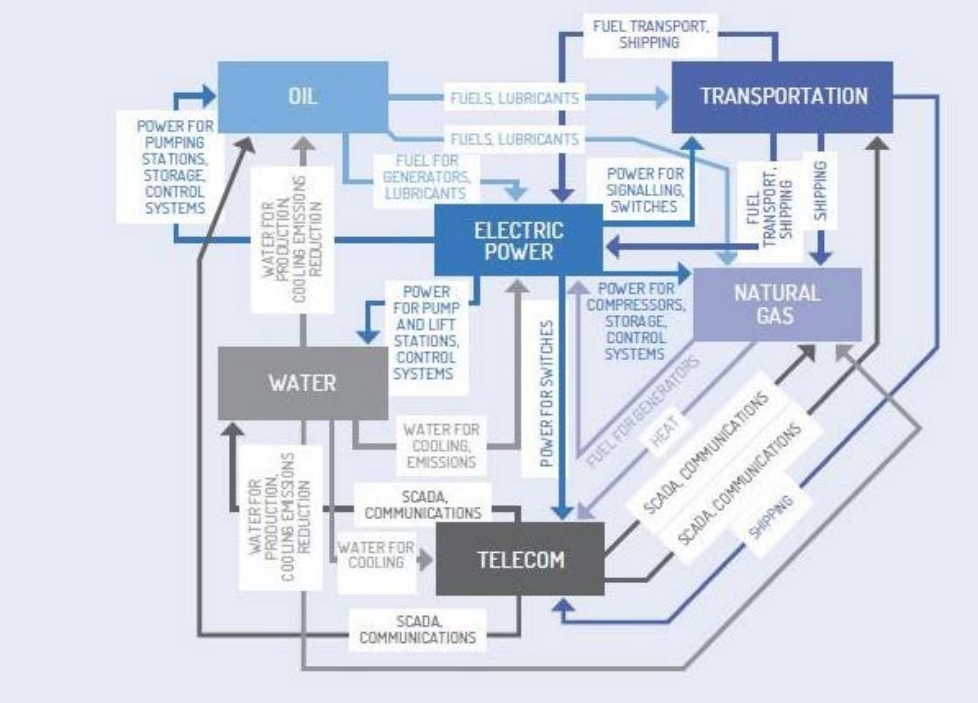
Recommendations for Mitigating the Risk

1. NERC should assess the risks of attack scenarios on midstream or interstate natural gas pipelines, particularly where natural gas availability will impact the availability of generation and the reliability of the BPS.
2. E-ISAC should encourage continued industry efforts on workforce cyber education to raise awareness of methods and tactics used by cyber attackers (e.g. email phishing, credential theft).
3. NATF and NAGF should develop supply chain cyber security superior practices.
4. E-ISAC should execute a long-term strategy to improve cyber and physical security information-sharing and risk analysis and increase engagement within the electric sector, as well as with other ISACs.
5. NATF, NAGF, Trades, and E-ISAC should develop tiered security performance metrics. Such metrics would track and evaluate events and use predictive analysis to identify and address prospective vulnerabilities on a risk-prioritized basis.
6. NERC should facilitate the development of planning approaches, models and simulation approaches that reduce the number of critical facilities and mitigate the impact relative to the exposure to attack.
7. NERC's Electro-Magnetic Pulse (EMP) taskforce should highlight key risks areas arising from EPRI's EMP analysis for timely industry action.

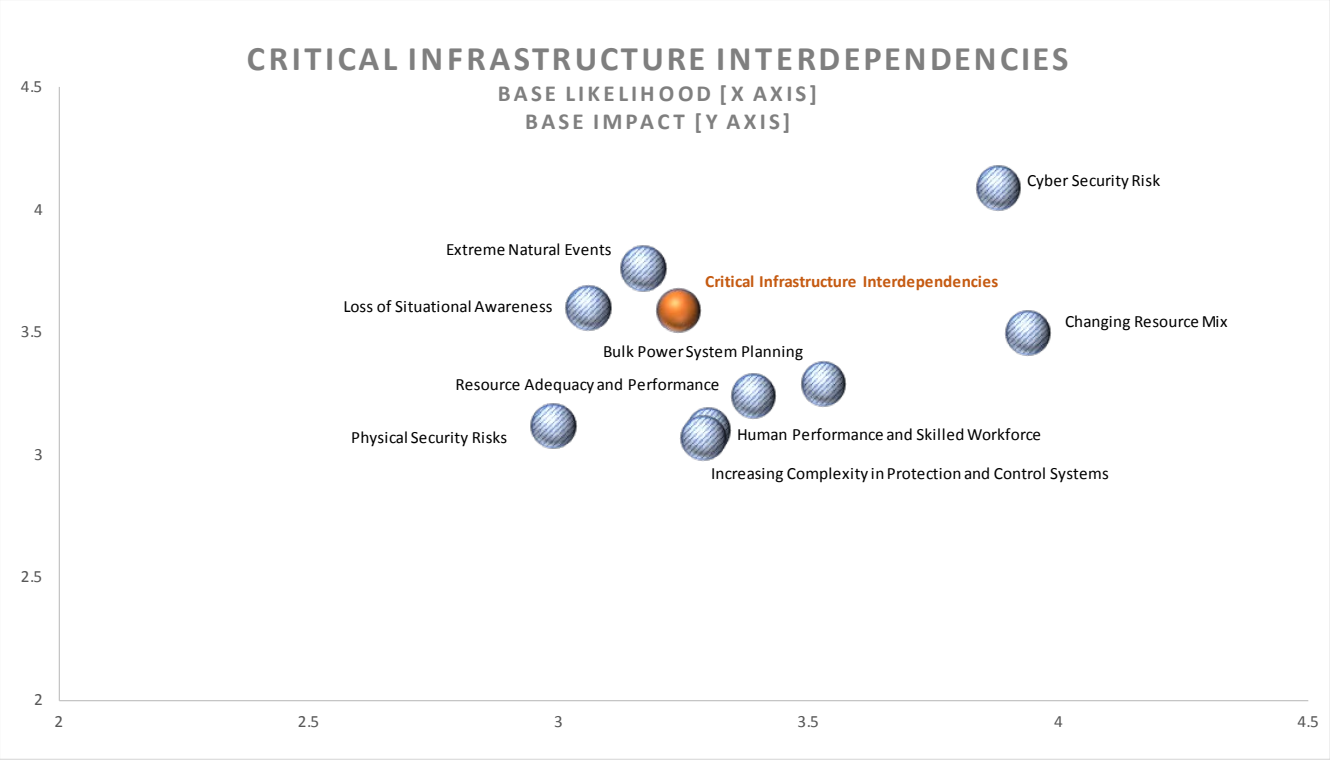
Risk Profile #4: Critical Infrastructure Interdependencies

Statement of the Risk

Significant and evolving critical infrastructure sector (e.g., communications, water/wastewater) and subsector (e.g., oil, natural gas) interdependencies are not fully or accurately characterized, resulting in incomplete information about prospective BPS response to disruptions originating from or impacting other sectors or subsectors and resultant reliability and security implications.



Risk Mapping



Descriptors of the Risk

- Sector interdependence is becoming more critical, such as the added importance of digital communications for electric system protection and control, as well as voice communications for emergency response and restoration.

- Subsector interdependence is increasing (e.g., growing reliance on natural gas as an electrical generation fuel source), creating the potential for more limiting contingencies—including single point failures.
- Cross-sector and -subsector implications and coordination are not routinely socialized or thoroughly tested during drills.
- Governmental oversight and regulatory constructs differ widely among the sectors and subsectors, impeding information sharing and alignment.

Recommendations for Mitigating the Risk

1. NERC should identify and prioritize limiting conditions and/or contingencies arising from other sectors, which affect the BPS.
2. NERC and industry partners should host strategic interactions among critical infrastructure partners (both industry and regulators) to identify and align on mutual priorities.
3. NERC and industry partners should increase emphasis on cross-sector considerations in industry drills (NERC Grid-Ex, DOE drills, utility exercises e.g. SCE Resilient Grid Exercise).
4. NERC should conduct special regional assessments that address natural gas availability and pipeline impacts under physical attack scenarios.
5. EPRI and the DOE should continue their work on communication alternatives but also the use of same or similar technologies for critical SCADA data. New technologies should be explored that could assist in providing unique and hardened back-up telecommunication methods for the most critical data.
6. NERC and industry partners should conduct various meetings and conferences to highlight the importance of cross-sector interdependence and coordination such as NERC Reliability Summit, NATF/EPRI Resiliency Summits, and FERC/DOE Technical Conferences.

2019 Scope of Work
for the
Regional Standards Committee (RSC)

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

(a) Managing and maintaining the NPCC Regional Standards Development Process.
(b) Managing and maintaining the NPCC Directory and Criteria Development and Review Process.
(c) Providing consolidated NPCC Regional review and comments to existing and proposed NERC Standards in accordance with the NERC Reliability Standards Development Processes.
(d) Reviewing FERC Orders, Rulings and Notice of Proposed Rulemakings (NOPRs) related to Reliability Standards, by providing a forum for developing consensus.
(e) Reviewing any new and revised NERC Reliability Standard Audit Worksheet (RSAW), as may be requested by the NPCC Compliance Committee, and submit comments to NERC as necessary.
(f) Providing consolidated NPCC Regional review and comments to the existing and proposed NERC Standards Development Processes Manual and to the NERC Rules of Procedure as they relate to Standards Development.
(g) Determining the need for and development of NERC and Regional Standards, Variances to NERC Standards, modifications to NPCC Directories and Criteria, and/or interpretations and clarifications thereof.
(h) In coordination with the Compliance Committee, address issues identified through the NPCC Regional Feedback Mechanism to continually improve standards and NERC documents which includes Guidelines and other technical material.
(i) In coordination with the Reliability Coordinating Committee, address issues identified through the "Distributed Energy Resource (DER) BES Impact Reporting Form", conduct, maintain, and further develop the process as necessary.
(j) Providing a forum for sharing viewpoints and opinions with the goal of achieving consensus regarding reliability attributes of various forms of industry standards, guidance and/or regulations.

Subsequent to receiving comments from NPCC stakeholders, the RSC will be responsible for submitting those consensus Regional comments to NERC.

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

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

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

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

Members of the RSC will be nominated by their respective companies. NPCC RSC leadership (RSC Chairperson and Co-Vice Chairpersons) will review and consider the approval of all nominations to the RSC. The nominations will include contact information and qualifications to serve on the committee. Each of the NPCC Sectors as defined in the NPCC Amended and Restated Bylaws will be open to representation on the RSC in accordance with the NPCC Amended and Restated Bylaws.

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

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

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

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

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

scheduled meetings.

A. NPCC Regional Standards Process Responsibilities

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

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

B. NPCC Directory and Criteria Process Responsibilities

The RSC provides oversight for the development of NPCC Directories and the Criteria within each document. The RSC will provide guidance to all NPCC Committees, Task Forces and Working Groups regarding NPCC documents including Directories, Criteria Procedures and Guidelines. The RSC will also maintain and oversee the Directory Development and Revision Manual and related processes.

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

C. NERC Reliability Standards Responsibilities

The RSC will:

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

Processes Manual and Rules of Procedure as they apply to Reliability Standards, and provide NPCC members with basic information (or assistance with the NERC Website) for a common understanding of the processes.

- Coordinate the activities of NPCC members on Standard Drafting Teams, and encourage NPCC representation on all Standard Drafting Teams.
- Coordinate with the CC any NPCC input to CMEP Implementation Guidance documents in accordance with the CC process for submitting implementation guidance to NERC.
- Participate in the NERC Standards Efficiency Review and coordinate Regional participation in related efforts.
- Remain engaged as NPCC experiences further penetration of DER, energy storage devices and undergoes the public policy driven changing resource mix to identify reliability risks and opportunities and to promote solutions to known and newly identified adverse impacts to reliability.
- Coordinate with State and Provincial Governmental authorities on solutions to current and anticipated reliability risks as well as addressing resilience.

D. FERC Activities Affecting Standards

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

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

Northeast Power Coordinating Council, Inc.
Regional Standards Committee
Work Plan for Calendar Years 2019-2020

The following Regional Standards Committee (RSC) Work Plan activities for the calendar years of 2019 -2020 will be consistent with the NPCC 2019 and 2020 Business Plans and Budgets, Organizational and Strategic Goals, both approved and in draft, and will also continue to be supportive of the ongoing periodic reviews, standards development, standards efficiency review, and metric activities. Also, the Work Plan is responsive to the NERC Reliability Standards Development Process, the ERO Enterprise Long-Term Strategy, and the ERO Enterprise Operating Plan.

NPCC Reliability Standards Committee Program Responsibilities (related to Standards)

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

1. Monitor NERC's Reliability Issues Steering Committee (RISC) risk profiles and other reliability related issues and priorities for potential incorporation into NERC and NPCC Standards and Criteria, for removal from standards or for potential incorporation into guidelines or other non-standards-based solutions. Provide and coordinate NPCC's input into those decisions.
2. Coordinate and provide input to the development and prioritization of ERO reliability standards within the NERC Reliability Standards Development Plan through active Regional participation in the Periodic Review Standing Review Team.
3. Review and support the ERO standards efficiency initiative and ongoing standards development work which is defined to be a core set of results-based standards achieving an adequate level of reliability. Provide ongoing input to the Periodic Review Template used to determine the efficacy of standards.
4. Continue to coordinate Regional input for cost effectiveness activities conducted during NERC's Standards Development program.
5. Oversee, and participate in the Regional Standards Development Process and base any development, revision or retirement of NPCC Regional Reliability Standards on the reliability related needs of the Region or continent-wide ERO standards such as the ongoing revision of NPCC PRC-006-NPCC-1(new version 2) Underfrequency Load Shedding
6. Engage in the NERC Compliance Guidance Policy process. Support the inputs through the NPCC Compliance Committee by providing technical and policy related opinions as necessary.
7. Coordinate NPCC Regional Standards development activity with NERC Standards development activity to avoid duplication and ensure resources are available for efficient and effective standards development and implementation.
8. Coordinate NPCC participation in reviews and revisions of NERC Standards when addressing reliability directives from FERC and any Provincial Governmental Authority directives.
9. Participate in NERC and NPCC standards development activities related to resilience.
10. Address emerging issues FERC has identified with the NPCC Regional Standard Processes to promote consistency and support of the ERO Enterprise Alignment. Maintain and revise the NPCC process as required in 2019.
11. Conduct thorough reviews of all NERC Standards being developed or revised and coordinate timely

consensus based comments within the NPCC Region based on reliability needs, results-based requirements, and Periodic Reviews.

12. Develop and submit Standard Authorization Requests (SARs) for revisions when necessary to improve Standards and address reliability related issues for approved or draft Standards utilizing input from the NPCC Regional Feedback Mechanism to improve the quality and efficacy of standards.
13. Develop, as needed, any Interconnection Wide (Quebec) Regional variances for NERC Reliability Standards and NPCC Regional Standards in accordance with the NPCC Regional Standard Process Manual.
14. Develop ballot recommendations or provide a list of reliability or compliance issues to RSC members and NERC Registered Ballot Pool entities within NPCC for all NERC Standards under development.
15. Review and develop ballot recommendations for all NERC formal interpretations to Standards.
16. Provide guidance to NPCC Regional Standard Drafting Teams in critical areas of results-based Standards, Violation Severity Levels, and Violation Risk Factor development as well as ensuring quality.
17. Respond to FERC and Provincial filings and interrogatories on issues related to Regional and NERC Standards as requested.
18. Serve as a liaison for the Northeast Region to the NERC Reliability Issues Steering Committee for all new and emerging reliability risks.
19. Participate in the proceedings of various NERC groups to contribute to the continual improvement of NERC Standards and processes. These groups include but are not limited to:
    a. NERC Standards Committee (SC)
    b. NERC Standards Committee Process Subcommittee (SCPS)
    c. NERC Project Management Oversight Subcommittee (PMOS)
    d. NERC SAR and Standards Drafting Teams (SDTs)
    e. NERC Reliability Issues Steering Committee (RISC)
    f. NERC Standards Efficiency Review (SER) Teams
20. Manage the development and revision of the Regional Reliability Directories including Criteria clarifications as necessary and review all NPCC Criteria to avoid duplication and ensure consistency with NERC or regional Reliability Standards, identify the incremental reliability benefit and potential cost-effective alternatives to meeting the Northeast's reliability objectives.
21. Develop proposed standards and standard clarifications utilizing regional technical committees as assigned by the NPCC Reliability Coordinating Committee, RSC or as identified through the NPCC Regional Feedback Mechanism.
22. Work with the NPCC CC to develop the necessary compliance elements of the Regional Standards, for example, Violation Severity Levels (VSLs).
23. Revise and implement the NPCC Cost Effective Analysis Procedure and apply it to Directories being revised or developed, as needed. Promote and participate in the NERC cost effectiveness analysis activities conducted during formal industry comment periods of the ERO draft continent-wide Standards.
24. Ensure that the appropriate NPCC Task Forces review NERC Standards-related issuances, and provide input to support development of a NPCC consensus opinion.
25. Solicit technically qualified candidates from NPCC stakeholder companies to participate on each of the NERC Standard Drafting Teams and additional members to the regional drafting teams. Ensure sufficient regional representation exists on the drafting teams.
26. Educate and notify NPCC Region stakeholders and regulators about issues related to Standards development.
27. Participate in two scheduled NPCC Compliance and Standards Workshops
28. Participate in the revision and redrafting of the NERC Rules of Procedure and other documents related to standards development
29. Coordinate implementation of the NERC Standards development processes and NPCC Regional Standard processes and recommend revisions as necessary.
30. Coordinate with the Reliability Coordinating Committee, all activities related to input received from the "Distributed Energy Resources BES Impact Reporting Form."
31. Provide oversight, and further develop as may be necessary, the process, information and promotion of the "Distributed Energy Resources BES Impact Reporting Form."

32. Coordinate and work with State and Provincial Governmental Authorities to address reliability and resilience related issues associated between DERs, energy storage and the ERO or Regional Standards.

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

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

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

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

~~15-day informal comment period~~ This is the second draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	04/18/2018
SAR posted for comment	03/19/18 – 03/28/18

Anticipated Actions	Date
~~XX~~45-day formal or informal comment period with ballot	11/26/2018 – 01/09/2019
~~XX~~45-day formal or informal comment period with additional ballot	TBD
~~XX~~10-day final ballot	TBD
Board adoption	TBD

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: Frequency Response and Frequency Bias Setting**
2. **Number: BAL-003-~~1.1~~2**
3. **Purpose:** To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority
       - **4.1.1.1.** Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.
     - **4.1.2.** Frequency Response Sharing Group
5. **Effective Date:** See Implementation Plan for BAL-003-~~1.1~~2.

B. Requirements and Measures

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. *[Risk Factor: High][Time Horizon: Real-time Operations]*

M1. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.

R2. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. *[Risk Factor: Medium][Time Horizon: Operations Planning]*

M2. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium-][Time Horizon: Operations Planning]*

3.1 Less than zero at all times, and

3.2 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.

M3. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: *[Risk Factor: Medium-][Time Horizon: Operations Planning]*

- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or
- The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

M4. The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.
- The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted 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.

- For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most ~~30~~15% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 15% but by at most 30% or by more than ~~15~~ 30 MW/0.1 Hz, whichever is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than ~~1~~30% but by at most ~~30~~45% or ~~15~~ 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than ~~30~~45% or by more than ~~15~~ 45 MW/0.1 Hz, whichever is the greater deviation from its FRO.
R2.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	The Balancing Authority that is a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%.
R4.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		validated or calculated value.	validated or calculated value.	The Balancing Authority failed to change the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.

D. Regional Variances

None.

E. Associated Documents

~~Link to the Implementation Plan and other important associated documents.~~

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition
0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added "1."; changed hyphen to "en dash." Changed font style for "Appendix 1" to Arial; updated version number to "0.1b"	Errata
0.1b	October 29, 2008	BOT approved errata changes	Errata
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata
0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12
1	January 16, 2014	FERC Order issued approving BAL-003-1. (Order becomes effective for R2, R3, and R4 April 1, 2015. R1 becomes effective April 1, 2016.)	
1	May 7, 2014	NERC Board of Trustees adopted revisions to VRF and VSLs in Requirement R1.	
1	November 26, 2014	FERC issued a letter order approved VRF and VSL revisions to Requirement R1.	
1.1	August 25, 2015	Added numbering to Introduction section, corrected parts numbering for R3, and adjusted font within section M4.	Errata

Version	Date	Action	Change Tracking
1.1	November 13, 2015	FERC Letter Order approved errata to BAL-003-1.1. Docket RD15-6-000	Errata

Standard Attachments

Attachment A

BAL-003-~~1~~ 2 Frequency Response ~~&~~ and Frequency Bias Setting Standard

Supporting Document

Interconnection Frequency Response Obligation ~~(IFRO)~~

The ERO, in consultation with regional representatives, has established a target ~~contingency protection criterion~~reliability ~~objective~~criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). ~~The default IFRO listed in Table 1 is based on the resource contingency criteria (RCC), w~~which is the largest category C (N-2) event identified except for the Eastern Interconnection, which uses the largest event in the last 10 years. A maximum delta frequency (MDF) is calculated by adjusting a starting frequency for each Interconnection by the following:

~~Prevailing UFLS first step~~

- ~~CC_{Adj} which is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data~~
- ~~CB_R which is the statistically determined ratio of the Point C to Value B~~
- ~~BC'_{Adj} which is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.~~

~~The IFRO for each Interconnection in Table 1 is then calculated by dividing the RCC MWs by 10 times the MDF. In the Eastern Interconnection there is an additional adjustment (BC'_{Adj}) for the event nadir being below the Value B due to primary frequency response withdrawal. This IFRO includes uncertainty adjustments at a 95 % confidence level.~~ Detailed descriptions of the calculations used in Table 1 below are defined in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.

Interconnection	Eastern	Western	ERCOT	HQ	Units
~~Starting Frequency (F_{Start})~~	~~59.974~~	~~59.976~~	~~59.963~~	~~59.972~~	~~Hz~~
~~Prevailing UFLS First Step~~	~~59.5*~~	~~59.5~~	~~59.3~~	~~58.5~~	~~Hz~~
~~Base Delta Frequency (DF_{Base})~~	~~0.474~~	~~0.476~~	~~0.663~~	~~1.472~~	~~Hz~~
~~CC_{ADJ}~~	~~0.007~~	~~0.004~~	~~0.012~~	~~N/A~~	~~Hz~~
~~Delta Frequency (DF_{CC})~~	~~0.467~~	~~0.472~~	~~0.651~~	~~1.472~~	~~Hz~~
~~CB_R~~	~~1.000~~	~~1.625~~	~~1.377~~	~~1.550~~	
~~Delta Frequency (DF_{CBR})~~	~~0.467~~	~~0.291~~	~~0.473~~	~~0.949~~	~~Hz~~
~~BC'_{ADJ}~~	~~0.018~~	~~N/A~~	~~N/A~~	~~N/A~~	~~Hz~~
Max. Delta Frequency (MDF)	0.41~~949~~	0.28~~091~~	0.40~~673~~	0.94~~69~~	

Resource ~~Contingency~~ Loss Protection Criteria (RLP~~C~~C)*	**3~~4~~,209~~500~~**	**2,85~~74~~0**	**2,750**	**2~~1~~,0~~7~~00**	MW
Credit for Load Resources (CLR)		**120~~300~~**	**1,209,~~400~~****		MW
Current IFRO (OY 2018)	**-1,015**	**-858**	**-381**	**-179**	MW/0.1 Hz
First-Step IFRO**~~IFRO~~	**-915~~-1,002~~**	**-975~~840~~**	**-380~~286~~**	**-211~~179~~**	MW/0.1 Hz
Second-Step IFRO**	**-815**				
Final IFRO**	**-766**				

Table 1: Interconnection Frequency Response Obligations (base year)

**~~These values are updated using preliminary information collected by the Standard Drafting Team.~~*These values are evaluated annually for changes in each Interconnection.*

***To reduce risk, the Eastern Interconnection IFRO will be stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step down process, Interconnection Frequency Response Measure (FRM) declines by more than 10~~%~~ percent, the ERO will halt the reduction in IFRO until such time~~s~~ that a determination can be made as to the cause of the degradation~~what is impacting Interconnection FRM~~.*

~~*The Eastern Interconnection UFLS set point listed is a compromise value set midway between the stable frequency minimum established in PRC-006-1 (59.3 Hz) and the local protection UFLS setting of 59.7 Hz used in Florida and Manitoba.*~~

~~***In the Base Obligation measure for ERCOT, 1400 MW (Load Resources triggered by Under Frequency Relays at 59.70 Hz) was reduced from its Resource Contingency Criteria level of 2750 MW to get 239 MW/0.1 Hz. This was reduced to accurately account for designed response from Load Resources within 30 cycles.*~~

~~An Interconnection may propose alternate IFRO protection criteria to the ERO by submitting a SAR with supporting technical documentation.~~

Balancing Authority Frequency Response Obligation ~~(FRO)~~ and Frequency Bias Setting

~~The ERO will manage the administrative procedure for annually assigning an FRO and implementation of the Frequency Bias Setting for each Balancing Authority. The annual timeline for all activities described in this section are shown below.~~

For a multiple Balancing Authority interconnection, the Interconnection FRO~~Frequency Response Obligation~~ shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. ~~-~~The FRO allocation will be based on the following method:

$$\mathrm{FRO}_{\mathrm{BA}} = \mathrm{IFRO} \quad \times \frac{\text{Annual Gen}_{\mathrm{BA}} + \text{Annual Load}_{\mathrm{BA}}}{\text{Annual Gen}_{\mathrm{Int}} + \text{Annual Load}_{\mathrm{Int}}}$$

Where:

- Annual $\mathrm{Gen}_{\mathrm{BA}}$ is the total annual ~~"~~o~~O~~utput of g~~G~~enerating p~~P~~lants~~"~~ within the Balancing Authority Area (BAA)~~., on FERC Form 714, column c of Part II - Schedule 3.~~
- Annual $\mathrm{Load}_{\mathrm{BA}}$ is total annual Load within the BAA~~, on FERC Form 714, column e of Part II - Schedule 3~~.
- Annual $\mathrm{Gen}_{\mathrm{Int}}$ is the sum of all Annual $\mathrm{Gen}_{\mathrm{BA}}$ values reported in that interconnection.
- Annual $\mathrm{Load}_{\mathrm{Int}}$ is the sum of all Annual $\mathrm{Load}_{\mathrm{BA}}$ values reported in that interconnection.

~~The data used for this calculation is from the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.~~

~~Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data to the ERO for use in the FRO Allocation process.~~

Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO's.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_{A} and measure the group response to all events in the reporting year on a single FRS Form 1, or
- ~~Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.~~ Submit a joint Form 1 with

the "FRSG" tab completed for the aggregate performance of the participating Balancing Authorities~~As~~.

Balancing Authorities that merge or ~~that~~ transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's ~~Frequency Response Measure (~~FRM~~)~~, Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. In addition, each Balancing Authority will report its two largest potential resource losses and any applicable N-2 RAS events in the form. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A Balancing Authority using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the Balancing Authority chooses between 100~~%~~ percent and 125~~%~~ percent of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a ~~Frequency Response Sharing Group~~FRSG will need to calculate its stand-alone ~~Frequency Response Measure~~FRM using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined Balancing Authorities' areas on FRS Form 1 as described in Requirement R4.

~~There are occasions when changes are needed to Bias Settings outside of the normal schedule. Examples are footprint changes between Balancing Authorities and major changes in load or generation or the formation of new Balancing Authorities. In such cases the changing Balancing Authorities will work with their Regions, NERC and the Resources Subcommittee to confirm appropriate changes to Bias Settings, FRO, CPS limits and Inadvertent Interchange balances.~~

~~If there is no net change to the Interconnection total Bias, the Balancing Authorities involved will agree on a date to implement their respective change in Bias Settings. The Balancing Authorities and ERO will also agree to the allocation of FRO such that the sum remains the same.~~

~~If there is a net change to the Interconnection total Bias, this will cause a change in CPS2 limits and FRO for other Balancing Authorities in the Interconnection. In this case, the ERO will notify the impacted Balancing Authorities of their respective changes and provide an implementation window for making the Bias Setting changes.~~

~~The ERO, in consultation with regional representatives, has established a target contingency protection criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). Detailed descriptions of the IFRO calculations are defined in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.~~[1]

Frequency Response Measure ~~(FRM)~~

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event ~~from~~ in a Balancing Authority area that is used to calculate its Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is ~~basically~~ the change in its Net Actual Interchange on its tie lines with ~~its~~ adjacent Balancing Authorities divided by the change in Interconnection frequency. ~~(~~Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_I) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year.[2] ~~As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.)~~

The ERO will use a standardized sampling interval of approximately 16 seconds before the event, up to the time of the event for the pre-event NA_I, and frequency (A values), and approximately 20 to 52 seconds after the event for the post-event NA_I (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority's Energy Management System (EMS).

---

[1] ~~Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard is available at https://www.nerc.com/pa/Stand/Frequency%20Response%20Project%20200712%20Related%20Files%20DL/BAL-003-1_Procedure-Clean_20120210.pdf~~

[2] As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt, or its EMS was unavailable. FRS Form 2 has instructions on how to correct the BA's data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct, FRS Form 1 will automatically calculate the Balancing Authority's FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing ~~authorities~~ Authorities to plan its operations, events with a "Point C" that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that ~~interconnection~~Interconnection. However, the calculation of the Balancing Authority response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual Balancing Authority's Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities ~~(BA)~~ to:

- Facilitate the assignment of Balancing Authority ~~Frequency Response Obligations (~~FRO~~)~~
- Calculate Balancing Authority ~~Frequency Response Measures (~~FRM~~)~~
- Determine Balancing Authority A Frequency Bias Settings ~~(FBS)~~

Target Business Date	Activity
~~April 30~~March 1	FRS Form 1 is posted by ~~The~~ the ERO* with all selected events for the operating year for BA usage~~reviews candidate frequency events and selects frequency events for the first quarter (December to February)~~.
April 1	BAs and FRSGs complete their frequency response forms for all four quarters, including the BAs' FBS calculations, returning the results to the ERO.
May 1	The ERO validates FBS values, computes the sum of all FBS values for each Interconnection.
~~May 10~~	~~Form1 is posted with selected events from the first quarter for BA usage by the ERO.~~
May 15	The BAs not required to file FERC Form 714 receive a request to provide load and generation data as described in the ***Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard***** to support FRO assignments and determining minimum FBS for the upcoming year. Data to be provided by July 15.~~The BAs receive a request to provide load and generation data as described in Attachment A to support FRO assignments and determining minimum FBS for BAs.~~
June 1	The BA implements any changes to their FBS.
November 1	The ERO assigns FRO values and Minimum FBS for the upcoming year to the BAs.

* If 4th quarter posting of FRS Form 1s is delayed, the ERO may adjust the other timelines in this table by a similar amount.

** Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

Formatted: Normal

~~Rationale~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption, the text from the rationale text boxes was moved to this section.~~

~~Rationale for R1:~~

~~Text, text, text~~

~~Rationale for R2:~~

~~Text, text, text~~

Standard Development Timeline

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

Description of Current Draft

This is the second draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	04/18/2018
SAR posted for comment	03/19/2018 – 03/28/2018

Anticipated Actions	Date
45-day formal or informal comment period with ballot	11/26/2018 – 01/09/2019
45-day formal or informal comment period with additional ballot	TBD
10-day final ballot	TBD
Board adoption	TBD

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: Frequency Response and Frequency Bias Setting**

2. **Number: BAL-003-2**

3. **Purpose:** To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   4.1.1.1. Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.

   4.1.2. Frequency Response Sharing Group

5. **Effective Date:** See Implementation Plan for BAL-003-2.

B. Requirements and Measures

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. *[Risk Factor: High][Time Horizon: Real-time Operations]*

M1. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.

R2. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. *[Risk Factor: Medium][Time Horizon: Operations Planning]*

M2. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

3.1 Less than zero at all times, and

3.2 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.

M3. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or
- The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

M4. The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.
- The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted 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.

- For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most 15% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 15% but by at most 30% or by more than 30 MW/0.1 Hz, whichever is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% but by at most 45% or 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 45% or by more than 45 MW/0.1 Hz, whichever is the greater deviation from its FRO.
R2.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	The Balancing Authority that is a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%.
R4.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		validated or calculated value.	validated or calculated value.	The Balancing Authority failed to change the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.

D. Regional Variances

None.

E. Associated Documents

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition
0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial; updated version number to “0.1b”	Errata
0.1b	October 29, 2008	BOT approved errata changes	Errata
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata
0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12
1	January 16, 2014	FERC Order issued approving BAL-003-1. (Order becomes effective for R2, R3, and R4 April 1, 2015. R1 becomes effective April 1, 2016.)	
1	May 7, 2014	NERC Board of Trustees adopted revisions to VRF and VSLs in Requirement R1.	
1	November 26, 2014	FERC issued a letter order approved VRF and VSL revisions to Requirement R1.	
1.1	August 25, 2015	Added numbering to Introduction section, corrected parts numbering for R3, and adjusted font within section M4.	Errata

Version	Date	Action	Change Tracking
1.1	November 13, 2015	FERC Letter Order approved errata to BAL-003-1.1. Docket RD15-6-000	Errata

Standard Attachments

Attachment A

BAL-003-2 Frequency Response and Frequency Bias Setting Standard

Supporting Document

Interconnection Frequency Response Obligation

The ERO, in consultation with regional representatives, has established a target reliability criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). Detailed descriptions of the calculations used in Table 1 below are defined in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.

Interconnection	Eastern	Western	ERCOT	HQ	Units
Max. Delta Frequency (MDF)	**0.419**	**0.280**	**0.406**	**0.946**	
Resource Loss Protection Criteria (RLPC)*	**3,209**	**2,850**	**2,750**	**2,000**	MW
Credit for Load Resources (CLR)		**120**	**1,209**		MW
Current IFRO (OY 2018)	**-1,015**	**-858**	**-381**	**-179**	MW/0.1 Hz
First-Step IFRO**	**-915**	**-975**	**-380**	**-211**	MW/0.1 Hz
Second-Step IFRO**	**-815**				
Final IFRO**	**-766**				

Table 1: Interconnection Frequency Response Obligations (base year)

**These values are evaluated annually for changes in each Interconnection.*

***To reduce risk, the Eastern Interconnection IFRO will be stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step down process, Interconnection Frequency Response Measure (FRM) declines by more than 10 percent, the ERO will halt the reduction in IFRO until such time that a determination can be made as to the cause of the degradation.*

Balancing Authority Frequency Response Obligation and Frequency Bias Setting

For a multiple Balancing Authority interconnection, the Interconnection FRO shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. The FRO allocation will be based on the following method:

$$\text{FRO}_{\text{BA}} = \text{IFRO} \quad \times \frac{\text{Annual Gen}_{\text{BA}} + \text{Annual Load}_{\text{BA}}}{\text{Annual Gen}_{\text{Int}} + \text{Annual Load}_{\text{Int}}}$$

Where:

- Annual Gen_{BA} is the total annual output of generating plants within the Balancing Authority Area (BAA).
- Annual Load_{BA} is total annual Load within the BAA.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual Load_{Int} is the sum of all Annual Load_{BA} values reported in that interconnection.

Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO's.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_{A} and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Submit a joint Form 1 with the "FRSG" tab completed for the aggregate performance of the participating Balancing Authorities.

Balancing Authorities that merge or transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's FRM, Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. In addition, each Balancing Authority will report its two largest potential resource losses and any applicable N-2 RAS events in the form. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A Balancing Authority using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the Balancing Authority chooses between 100 percent and 125 percent of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a FRSG will need to calculate its stand-alone FRM using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined Balancing Authorities' areas on FRS Form 1 as described in Requirement R4.

Frequency Response Measure

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event in a Balancing Authority area that is used to calculate its Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is the change in its Net Actual Interchange on its tie lines with adjacent Balancing Authorities divided by the change in Interconnection frequency. Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_I) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year.[1]

The ERO will use a standardized sampling interval of approximately 16 seconds before the event, up to the time of the event for the pre-event NA_I, and frequency (A values), and approximately 20 to 52 seconds after the event for the post-event NA_I (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority's Energy Management System (EMS).

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt, or its EMS was unavailable. FRS Form 2 has instructions on how to

[1] As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.

correct the BA's data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct, FRS Form 1 will automatically calculate the Balancing Authority's FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing Authorities to plan its operations, events with a "Point C" that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that Interconnection. However, the calculation of the Balancing Authority response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual Balancing Authority's Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities to:

- Facilitate the assignment of Balancing Authority FRO
- Calculate Balancing Authority FRM
- Determine Balancing Authority Frequency Bias Settings

Target Business Date	Activity
March 1	FRS Form 1 is posted by the ERO* with all selected events for the operating year for BA usage.
April 1	BAs and FRSGs complete their frequency response forms for all four quarters, including the BAs' FBS calculations, returning the results to the ERO.
May 1	The ERO validates FBS values, computes the sum of all FBS values for each Interconnection.
May 15	The BAs not required to file FERC Form 714 receive a request to provide load and generation data as described in the ***Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard***** to support FRO assignments and determining minimum FBS for the upcoming year. Data to be provided by July 15.
June 1	The BA implements any changes to their FBS.
November 1	The ERO assigns FRO values and Minimum FBS for the upcoming year to the BAs.

* If 4th quarter posting of FRS Form 1s is delayed, the ERO may adjust the other timelines in this table by a similar amount.

** Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2017-01 Modifications to BAL-003-1.1

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard BAL-003-2. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements. Please note, the SDT is only proposing to change the VSL for Requirement R1. As a result, justification is only provided for the VSL for Requirement R1

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures; 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 BES instability, separation, or a cascading sequence of failures, or could place the BES 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 BES, or the ability to effectively monitor and control the BES. However, violation of a medium risk requirement is unlikely to lead to BES 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 BES, or the ability to effectively monitor, control, or restore the BES. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

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 BES, or the ability to effectively monitor and control the BES; 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 BES, or the ability to effectively monitor, control, or restore the BES.

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 (BPS). In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard..

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a-per violation per-day basis is the "default" for penalty calculations.

VRF Justification for BAL-003-1.1, Requirement R1
The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R1
This justification is provided on the following page.

VRF Justification for BAL-003-1.1, Requirement R2
The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R2
The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VRF Justification for BAL-003-1.1, Requirement R3
The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R3
The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VRF Justification for BAL-003-1.1, Requirement R4
The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R4
The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSLs for BAL-003-2, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority's (BA)s, or Frequency Response Sharing Group's (FRSG)s, Frequency Response Measure (FRM) was less negative than its Frequency Response Obligation (FRO) by more than 1% but by at most 15% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The BA's, or (FRSG)s, FRM was less negative than its FRO by more than 15% but by at most 30% or by more than 30 MW/0.1 Hz, whichever is the greater deviation from its FRO.	The BA's, or FRSGs, FRM was less negative than its FRO by more than 30% but by at most 45% or 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The BA's, or FRSG's, FRM was less negative than its FRO by more than 45% or by more than 45 MW/0.1 Hz, whichever is the greater deviation from its FRO.

VSL Justifications for BAL-003-2, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is not applicable since there was not a requirement mandating a certain level of Frequency Response prior to 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	Proposed VSL's are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the amount the calculated FRM is less negative than FRO.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Proposed VSL's do not expand on what is required. The VSL's assigned only consider results of the calculation required. Proposed VSL's are 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 based on a single violation and not a cumulative violation methodology.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2017-01 Modifications to BAL-003-1.1
Reliability Standard BAL-003-2

Applicable Standard

- Standard BAL-003-2 — Frequency Response and Frequency Bias Setting

Requested Retirement(s)

- Standard BAL-003-1.1 — Frequency Response and Frequency Bias Setting

Applicable Entities

- Balancing Authority
  - Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.
- Frequency Response Sharing Group

Background

The BAL-003-2 Phase I portion of the project revises the BAL-003-1.1 standard and process documents to address: (1) the inconsistencies in calculation of IFROs due to interconnection Frequency Response performance changes of Point C and/or Value B; (2) the Eastern Interconnection Resource Contingency Protection Criteria; (3) the frequency of nadir point limitations (currently limited to t0 to t+12); (4) clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities; and (5) enhancements to the BAL-003-1 FRS Forms that include the ability to collect and submit FRSG performance data. Additionally, the supporting procedural and process steps have been removed from Attachment A and captured in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.* This proposed document would be subject to approval by the North American Electric Reliability Corporation Operating Committee and Board of Trustees, and subject to informational filing with the Federal Energy Regulatory Commission, to facilitate timely process improvements as future lessons are learned.

Effective Date

BAL-003-2 — Frequency Response and Frequency Bias Setting

Where approval by an applicable governmental authority is required, the standard shall become effective on the first operating year (which begins on December 1) that is 90 days after the effective date of the

applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first operating year (which begins on December 1) that is 90 days after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

BAL-003-1.1 — Frequency Response and Frequency Bias Setting
Reliability Standard BAL-003-1.1 shall be retired immediately prior to the effective date of BAL-003-2 in the particular jurisdiction in which the revised standard is becoming effective.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

RELIABILITY | ACCOUNTABILITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

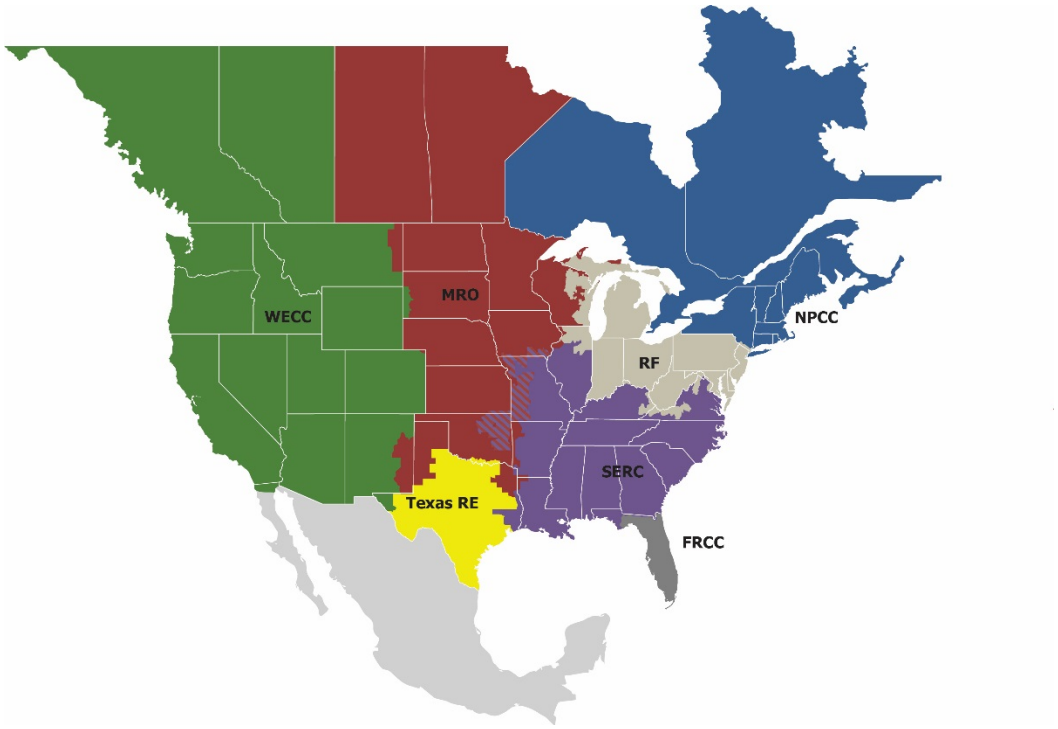
Table of Contents

Preface iii
Introduction iiv
Chapter 1: Event Selection Process 1
Event Selection Objectives 1
Event Selection Criteria 1
Quarterly 3
Annually 3
Chapter 2: Process for Adjusting Interconnection Minimum Frequency Bias Setting 4
Chapter 3: Interconnection Frequency Response Obligation Methodology 5

Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into seven RE boundaries as shown in the map and corresponding table below. The multicolored area denotes 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
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

This procedure (Procedure) outlines the Electric Reliability Organization (ERO) process for supporting the Frequency Response Standard (FRS). A ~~Procedure revision~~ request for revisions may be submitted to the Operating Committee (OC) of the ERO for consideration. The ~~revision~~ request must provide a technical justification for the suggested modification. The ERO shall publicly post the suggested modification for a 45-day formal comment period and discuss the ~~revision~~ request in a public meeting of the ERO OC. The ERO will make a recommendation to the NERC ~~BOT~~Board of Trustees (BOT), which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to this Procedure shall be filed with the Federal Energy Regulatory Commission (FERC) for informational purposes.

BAL-003-2 sets Interconnection Frequency Response Obligation (IFRO) to preset values subject to annual review. This procedure establishes the methods to be used for the annual review until Phase 2 of the SAR for Project 2017-01 has been addressed. If Frequency Response Measure (FRM) for the Eastern Interconnection degrades more than 10% in a year, the ERO will halt the reduction in IFRO until such time as a determination can be made as to the cause of the degradation.

Chapter 1: Event Selection Process

Event Selection Objectives

The goals of this procedure are to outline a transparent, repeatable process to annually identify a list of frequency events to be used ~~by Balancing Authorities (BA)~~ to calculate ~~their~~ Frequency Response to determine:

- Whether the Balancing Authority (BA) or Frequency Response Sharing Group (FRSG) met its Frequency Response Obligation, and
- An appropriate fixed Frequency Bias Setting.

Event Selection Criteria

1. The ERO will use the following criteria to select FRS ~~frequency~~ excursion events for analysis. The events that best fit the criteria will be used to support the FRS. ~~-~~The evaluation period for performing the annual Frequency Bias Setting and the ~~Frequency Response Measure (~~FRM~~)~~ calculation is December 1 of the prior year through November 30 of the current year.
2. The ERO will identify 20 to 35 frequency excursion events in each Interconnection for calculating the Frequency Bias Setting and the FRM. ~~-~~If the ERO cannot identify 20 frequency excursion events in a 12~~-~~ month evaluation period satisfying the criteria below, then similar acceptable events from the subsequent year's evaluation period will be included with the data set by the ERO for determining ~~FRS~~ compliance. ~~This is described later.~~
3. The ERO will use three criteria to determine if an acceptable frequency excursion event for the FRM has occurred:
   a. The change in frequency as defined by the difference from the A Value to Point C and the arrested frequency Point C exceeds the excursion threshold values specified for the Interconnection in Table 1 below.
      i. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline.
      ii. Point C is the arrested value of frequency observed within ~~12~~ 20 seconds following the start of the excursion.

Table 1.1: Interconnection Frequency Excursion Threshold Values

Interconnection	A Value to Pt C	Point C (Low)	Point C (High)
East	0.04Hz	< 59.96	> 60.04
West	0.07Hz	< 59.95	> 60.05
ERCOT	0.15Hz	< 59.90	> 60.10
HQ	0.30Hz	< 59.85	> 60.15

   b. The time from the start of the rapid change in frequency until the point at which Frequency has stabilized within a narrow range should be less than 18 seconds.
   c. If any data point in the B Value average recovers to the A Value, the event will not be included.

4. Pre-disturbance frequency should be relatively steady and near 60.000 Hz for the A Value. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline. For example, given the choice of the two events below, the one on the right is preferred as the pre-disturbance frequency is stable and also closer to 60 Hz.

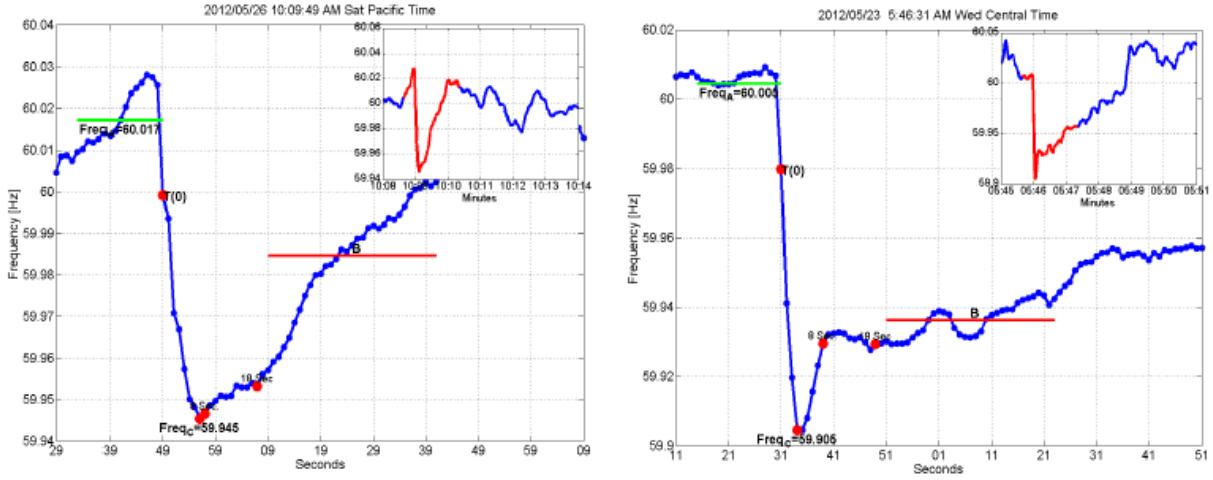


Figure 1.1: Pre-disturbance Frequency

5. Excursions that include 2 or more events that do not stabilize within 18 seconds will not be considered.
6. Frequency excursion events occurring during periods:
   a. when large interchange schedule ramping or load change is happening, or
   b. within 5 minutes of the top of the hour, will be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.
7. The ERO will select the largest (A Value to Point C) 2 or 3 frequency excursion *e*vents occurring each month. If there are not 2 frequency excursion events satisfying the selection criteria in a month, then other frequency excursion events should be picked in the following sequence:
   a. From the same event quarter of the year.
   b. From an adjacent month.
   c. From a similar load season in the year (shoulder vs. summer/winter)
   d. The largest unused event.

As noted earlier, if a total of 20 events are not available in an evaluation year, then similar acceptable events from the next year's evaluation period will be included with the data set by the ERO for determining Frequency Response Obligation (FRO) compliance. The first year's small set of data will be reported and used for Bias Setting purposes, but compliance evaluation on the FRO will be done using a 24-month data set.

To assist Balancing Authority preparation for complying with this standard, the ERO will provide quarterly posting of candidate frequency excursion events for the current year FRM calculation. The ERO will post the final list of frequency excursion events used for standard compliance as specified in Attachment A of ~~BAL-003-1~~the standard.

The following is a general description of the process that the ERO will use to ensure that BAs can evaluate events during the year in order to monitor their performance throughout the year.

~~Monthly~~

~~Candidate events will be initially screened by the "Frequency Event Detection Methodology" shown on the following link located on the NERC Resources Subcommittee area of the NERC website: http://www.nerc.com/docs/oc/rs/Frequency_Event_Detection_Methodology_and_Criteria_Oct_2011.pdf. Each month's list will be posted by the end of the following month on the NERC website, http://www.nerc.com/filez/rs.html and listed under "Candidate Frequency Events".~~

Quarterly

The ~~monthly~~ event lists will be reviewed quarterly, with the quarters defined as:

- December through February
- March through May
- June through August
- September through November

Based on criteria established in ~~the~~ this Procedure ~~"Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard"~~, events will be selected to populate the FRS Form 1 for each Interconnection. ~~-~~The FRS Form 1's will be posted on the NERC website, in the Resources Subcommittee area under the title "Frequency Response Standard Resources". Updated FRS Form 1's will be posted at the end of each quarter listed above after a review by the NERC Resources Subcommittee (RS)~~'~~ and its Frequency Working Group. ~~-~~While the events on this list are expected to be final, as outlined in the selection criteria, additional events may be considered, if the number of events throughout the year do not create a list of at least 20 events. ~~-~~It is intended that this quarterly posting of updates to the FRS Form 1 would allow BAs to evaluate the events throughout the year, lessening the burden when the yearly posting is made.

Annually

The final FRS Form 1 for each Interconnection, which would contain the events from all four quarters listed above, will be posted as specified in Attachment A. Each Balancing Authority reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO as specified in Attachment A using the final FRS Form 1. ~~-~~The ERO will check for errors and use the FRS Form 1 data to calculate CPS limits and FROs for the upcoming year.

Once the data listed above is fully reviewed, the ERO may adjust the implementation specified in Attachment A for changing the Frequency Bias Settings and CPS limits. ~~-~~This allows flexibility ~~in~~ when each BA implements its settings.

Chapter 2: Process for Adjusting Interconnection Minimum Frequency Bias Setting

This procedure outlines the process the ERO is to use for modifying minimum Frequency Bias Settings to better meet reliability needs. The ERO will adjust the Frequency Bias Setting minimum in accordance with this procedure. The ERO will post the minimum Frequency Bias Setting values on the ERO website along with other balancing standard limits.

Under BAL-003-~~1~~2, the minimum Frequency Bias Settings will be moved toward the natural Frequency Response in each ~~interconnection~~Interconnection. In the first year, the minimum Frequency Bias Setting for each ~~interconnection~~ Interconnection is shown in Table 2 below. Each Interconnection Minimum Frequency Bias Setting is based on the sum of the non-coincident peak loads for each BA from the currently available FERC 714 Report or equivalent. This non-coincident peak load sum is multiplied by the percentage shown in Table 2 to get the Interconnection Minimum Frequency Bias Setting. The Interconnection Minimum Frequency Bias Setting is allocated among the BAs on an ~~interconnection~~ Interconnection using the same allocation method as is used for the allocation of the Frequency Response Obligation (FRO).

Table 2.1: Frequency Bias Setting Minimums

Interconnection	Interconnection Minimum Frequency Bias Setting (in MW/0.1Hz)
Eastern	0.9% of non-coincident peak load
Western	0.9% of non-coincident peak load
ERCOT	N/A
HQ	N/A

*The minimum Frequency Bias Setting requirement does not apply to a Balancing Authority that is the only Balancing Authority in its Interconnection. These Balancing Authorities are solely responsible for providing reliable frequency control of their Interconnection. These Balancing Authorities are responsible for converting frequency error into a megawatt error to provide reliable frequency control, and the imposition of a minimum bias setting greater than the magnitude the Frequency Response Obligation may have the potential to cause control system hunting, and instability in the extreme.

The ERO, in coordination with the regions of each ~~interconnection~~Interconnection, will annually review Frequency Bias Setting data submitted by BAs. If an Interconnection's total minimum Frequency Bias Setting exceeds (in absolute value) the Interconnection's total natural Frequency Response by more (in absolute value) than 0.2 percentage points of peak load (expressed in MW/0.1Hz), the minimum Frequency Bias Setting for BAs within that Interconnection may be reduced (in absolute value) in the subsequent years FRS Form 1 based on the technical evaluation and consultation with the regions affected by 0.1 percentage point of peak load (expressed in MW/0.1Hz) to better match that Frequency Bias Setting and natural Frequency Response.

The ERO, in coordination with the regions of each Interconnection, will monitor the impact of the reduction of minimum frequency bias settings, if any, on frequency performance, control performance, and system reliability. If unexpected and undesirable impacts such as, but not limited to, sluggish post-contingency restoration of frequency to schedule or control performance problems occur, then the prior reduction in the minimum frequency bias settings may be reversed, and/or the prospective reduction based on the criterion stated above may not be implemented.

Chapter 3: Interconnection Frequency Response Obligation Methodology

The Interconnection Resource Loss Protection Criteria (RLPC) is calculated based a resource loss in accordance with the following process:

NERC will request BAs to provide their two largest resource loss values and largest resource loss due to an N-1or N-2 RAS event or largest resource as described above. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

BAs determine the two largest resource losses for the next operating year based on a review of the following items:

- The two largest Balancing Contingency Events due to a single contingency identified using system models in terms of loss measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.
- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FR Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If this RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation). DC lines such as the Pacific DC Intertie, which ties two sections of the same synchronous Interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B = 500 MW	Electrically separate

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Largest Resource Loss = 1500 MW Second Largest Resource Loss = 1400 MW Summation of two largest resource losses = 2900 MW Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated.

Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW N-2 RAS event BA1 Resource Loss A = 1150 MW BA1 Resource Loss B = 800 MW BA2 Resource Loss A = 1380 MW BA2 Resource Loss B = 1380 MW BA3 RAS = 1000 MW N-1 RAS event BA3 Resource Loss A = 800 MW BA3 Resource Loss B = 700 MW

~~This procedure outlines the process the ERO is to use for determining the Interconnection Frequency Response Obligation (IFRO).~~

~~The following are the formulae that comprise the calculation of the IFROs.~~

$$DF_{Base} = F_{Start} - UFLS$$

$$DF_{CC} = DF_{Base} - CC_{Adj}$$

$$DF_{CBR} = \frac{DF_{CC}}{CB_{R}}$$

$$MDF = DF_{CBR} - BC'_{Adj}$$

$$ARCC = RCC - CLR$$

$$IFRO = \frac{ARCC}{10 * MDF}$$

~~Where:~~

- ~~DF_{Base} is the base delta frequency.~~
- ~~FStart is the starting frequency determined by the statistical analysis.~~
- ~~UFLS is the highest UFLS trip setpoint for the interconnection.~~

- ~~CCAdj is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data.~~
- ~~DFCC is the delta frequency adjusted for the differences between 1-second and sub-second Point C observations for frequency events.~~
- ~~CBR is the statistically determined ratio of the Point C to Value B.~~
- ~~DFCBR is the delta frequency adjusted for the ratio of the Point C to Value B.~~
- ~~BC'ADJ is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.~~
- ~~MDF is the maximum allowable delta frequency.~~
- ~~RCC is the resource contingency criteria.~~
- ~~CLR is the credit for load resources.~~
- ~~ARCC is the adjusted resource contingency criteria adjusted for the credit for load resources.~~
- ~~IFRO is the interconnection frequency response obligation.~~

In this case, the ERO would determine the RLPC as follows: the summation of the two largest resource losses is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

Interconnection RLPC Values

Based on initial review, the numbers below would be representative of the RLPC for each Interconnection.

Eastern Interconnection:
Present RLPC = 4500 MW Load Credit = 0 MW
RESOURCE LOSS A = 1732 MW
RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

Western Interconnection:
Present RLPC = 2626 MW Load Credit = 120 MW
RESOURCE LOSS A = 1505 MW
RESOURCE LOSS B = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

ERCOT:
Present RLPC = 2750 MW Load Credit = 1209 MW
RESOURCE LOSS A = 1375 MW
RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
RESOURCE LOSS A = 1000 MW
RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Proposed Resource Loss Protection Criteria

Background and Current Methodologies

The Resource Loss Protection Criteria (RLPC) is the respective Interconnection design resource loss in MW, ~~-~~which is used to determine the Interconnection Frequency Response Obligation (IFRO).
An "N-2 Event" is defined as a single initiating event that leads to multiple (two or more) electrical facilities being removed from service. Examples of this are breaker failure events, bus faults, or double circuit tower outages.

Previously, the RLPC has been calculated from the largest N-2 events identified in each Interconnection, except for the Eastern Interconnection. In the Eastern Interconnection, the RLPC has been calculated using the largest single event in the previous ten years.

The RLPC value should be set for each Interconnection such that the underfrequency load shedding safety net is not activated for the largest N-2 Event. The ~~P~~previous BAL-003 IFRO methodology determined that the largest N-2 Event should not precipitate an underfrequency load shedding event. Ideally, the RLPC value should always equal or exceed the largest N-2 Event. If the RLPC is set to a larger value than the largest N-2 Event, the probability of an underfrequency load shedding event decreases. If the RLPC value is set to a value less than the largest N-2 Event, the probability of an underfrequency load shedding event increases.

A quantitative approach ~~to~~for selecting the RLPC can be implemented that minimizes the need for detailed system analysis to be performed annually.

Currently, each Balancing Authority (BA) or Reserve Sharing Group (RSG) determines its Most Severe Single Contingency (MSSC) with respect to resource loss as required by BAL-002-2(i), Requirement R2. The MSSC calculation is done in Real-time operations based on actual system configuration.

Relevant Definitions

For convenience, the definitions of the following terms defined in the Glossary of Terms used in NERC Reliability Standards are provided below. Where a conflict exists between the definition provided here and the definition in the Glossary, the definition in the Glossary shall control.

Most Severe Single Contingency:
The Balancing Contingency Event, due to a single contingency identified using system models maintained within the RSG or a BA's area that is not part of a RSG, that would result in the greatest loss (measured in Megawatts (MWs) of resource output used by the RSG or a BA that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Balancing Contingency Event:
Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

A. Sudden loss of generation:
   a. Due to:
      i. unit tripping, or
      ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
      iii. sudden unplanned outage of transmission Facility.
   b. And that causes an unexpected change to the responsible entity's Area Control ~~Area~~ Error (ACE).

B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.

C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Interconnection:
A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

Proposal

The Interconnection RLPC is calculated based on a resource loss in accordance with the following process:

NERC will request ~~Balancing Authorities~~BAs to provide: their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event or largest resource as described above. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

~~NERC will request Balancing Authorities or Frequency Response Sharing Groups to provide: their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event or largest resource as described above. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be voluntary on the part of the Balancing Authorities but will be needed to complete the calculation of the RLPC and IFRO.~~

~~Balancing Authorities~~BAs determine the two largest ~~potential~~ resource losses for the next operating year based on a review of the following items:

- The two largest Balancing Contingency Events due to a single contingency identified using system models in terms of loss measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.
- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FRS Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If th~~is~~e RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.
The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation). DC lines such as the Pacific DC Intertie, which ties two sections of the same synchronous interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B= 500 MW	Electrically separate

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Largest Resource Loss = 1500 MW
Second Largest Resource Loss = 1400 MW
Summation of two largest resource losses = 2900 MW
Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated.

Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW N-2 RAS event
BA1 Resource Loss A = 1150 MW
BA1 Resource Loss B = 800 MW
BA2 Resource Loss A = 1380 MW
BA2 Resource Loss B = 1380 MW
BA3 RAS = 1000 MW N-1 RAS event
BA3 Resource Loss A = 800 MW
BA3 Resource Loss B = 700 MW

In this ~~case~~case, the ERO would determine the RLPC as ~~follows,~~follows~~;~~: the summation of the two largest resource losses ~~are~~is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

~~North American~~ Interconnection ~~RPLC~~ RLPC Values

Based on initial review, the numbers below ~~are believed to~~would be representative of the RLPC for each Interconnection.

Eastern Interconnection:
Present RLPC = 4500 MW Load Credit = 0 MW
~~MSSC1~~RESOURCE LOSS A = 1732 MW
~~MSSC2~~RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

Western Interconnection:
Present RLPC = 2626 MW Load Credit = 120 MW
~~MSSC1~~RESOURCE LOSS A = 1505 MW
~~MSSC2~~RESOURCE LOSS B = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

ERCOT:
Present RLPC = 2750 MW Load Credit = 1209 MW
~~MSSC1~~RESOURCE LOSS A = 1375 MW
~~MSSC2~~RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
~~MSSC1~~RESOURCE LOSS A = 1000 MW
~~MSSC2~~RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with ballot	09/29/17 – 11/14/17

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

A. Introduction

1. **Title:** Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology

2. **Number:** FAC-015-1

3. **Purpose:** To ensure the Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments are coordinated with the Reliability Coordinator's System Operating Limits (SOL) Methodology.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Transmission Planner

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than ~~those established~~the owner-provided Facility Ratings used in ~~accordance with its~~ operations per the Reliability Coordinator's SOL Methodology. ~~If~~ The process may allow the ~~Planning Coordinator uses~~use of less limiting Facility Ratings ~~than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.~~if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Facility has higher Facility Ratings as a result of a planned upgrade, addition, or Corrective Action Plan;
- Facility Rating differences are due to variations in ambient temperature assumptions;
- The Planning Coordinator provided a technical rationale for using a less limiting Facility Rating to each affected Transmission Planner and Reliability Coordinator; or
- The Transmission Planner provided a technical rationale for using a less limiting Facility Rating to each affected Planning Coordinator and Reliability Coordinator.

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R1.

R2. Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure that System steady-state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits ~~established~~used in ~~accordance with its~~ operations per the Reliability Coordinator's SOL Methodology. ~~If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.~~ *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting System Voltage Limits if it provides a technical rationale for using a less limiting System Voltage Limits to each affected Transmission Planner and Reliability Coordinator.
- The Transmission Planner may use less limiting System Voltage Limits if it provides a technical rationale for using a less limiting System Voltage Limits to each affected Planning Coordinator and Reliability Coordinator.

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R2.

R3. Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria ~~established~~used in ~~its~~ operations per the Reliability Coordinator's SOL Methodology. ~~If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.~~ *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting stability performance criteria if it provides a technical rationale for using less limiting stability performance criteria to each affected Transmission Planner and Reliability Coordinator.
- The Transmission Planner may use less limiting stability performance criteria if it provides a technical rationale for using less limiting stability performance criteria to each affected Planning Coordinator and Reliability Coordinator.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R3.

~~**R4.** Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to~~

~~its Transmission Planners and to requesting Planning Coordinator's. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~

~~**M4.** Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator provided its information in accordance with Requirement R4.~~

~~**R5.** Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~

~~**M5.** Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Transmission Planner used the information provided by its Planning Coordinator in accordance with Requirement R5.~~

~~**R6.**~~R4. ~~Each Planning Coordinator~~and each Transmission Planner shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only) to each impacted Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner, and Generation Owner. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- ~~6~~4.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);
- ~~6~~4.2 The associated stability criteria used as part of determining the instability;
- ~~6~~4.3 The associated Contingency(ies) ~~which result(s) in~~and any Facilities critical to the instability, Cascading or uncontrolled separation;
- ~~6.4~~4.4 A description of the studied System conditions when the instability, Cascading or uncontrolled separation was identified;
- 4.5 Any Remedial Action Scheme action, undervoltage load shedding (UVLS) action, underfrequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; and
- 4.6~~.5~~ Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

~~**M6.**~~M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement ~~R6~~R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator and Transmission Planner shall keep evidence for Requirements R1 through ~~R6~~R4 for the most current year plus the previous three years.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	~~The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.~~N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but ~~did not document the technical justification.~~failed to identify the exclusion criteria allowing the use of less limiting Facility Ratings.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in its Reliability Coordinator's SOL Methodology.
R2.	N/A	~~The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.~~N/A	The Planning Coordinator or a Transmission Planner used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not ~~document the~~provide its	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with its

			technical ~~justification~~rationale.	Reliability Coordinator's SOL Methodology.
R3.	N/A	~~The Planning Coordinator used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.~~N/A	The Planning Coordinator or a Transmission Planner used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not ~~document the~~provide its technical ~~justification~~rationale.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that stability performance criteria used in ~~planning assessments~~Planning Assessments are equally limiting or more limiting than ~~those used in operations~~the stability performance criteria established in the Reliability Coordinator's SOL Methodology.
~~**R4.**~~	~~N/A~~	~~N/A~~	~~The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners.~~ ~~OR~~ ~~The Planning Coordinator failed to provide one element of the required information.~~	~~The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners.~~ ~~OR~~ ~~The Planning Coordinator failed to provide two or more elements of the required information.~~

~~R5.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Planner failed to use Facility Ratings, System steady-stability voltage limits, and stability performance criteria that were equally or more limiting than those provided by its Planning Coordinator.~~
~~R6~~R4.	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain one of the elements listed in Requirement ~~R6~~R4, Parts ~~6~~4.1 – 4.6.~~5.~~	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain two of the elements listed in Requirement ~~R6~~R4, Parts ~~6~~4.1 – 4.6.~~5.~~	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain three elements listed in Requirement ~~R6~~R4, Parts ~~6~~4.1 – 4.6.~~5.~~	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain four or more of the elements listed in Requirement ~~R6~~R4, Parts ~~6~~4.1 – 4.6.~~5~~. OR The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted

				Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner and Generator Owner.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1		Project 2015-09 SOL – Adopt new standard.	New

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with ballot	09/29/17 – 11/14/17

Anticipated Actions	Date
45-day formal comment period with additional ballot	August 2018 – October 2018
10-day final ballot	October 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology

2. **Number:** FAC-015-1

3. **Purpose:** To ensure the Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments are coordinated with the Reliability Coordinator's System Operating Limits (SOL) Methodology.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Transmission Planner

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the owner-provided Facility Ratings used in operations per the Reliability Coordinator's SOL Methodology. The process may allow the use of less limiting Facility Ratings if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Facility has higher Facility Ratings as a result of a planned upgrade, addition, or Corrective Action Plan;
- Facility Rating differences are due to variations in ambient temperature assumptions;
- The Planning Coordinator provided a technical rationale for using a less limiting Facility Rating to each affected Transmission Planner and Reliability Coordinator; or
- The Transmission Planner provided a technical rationale for using a less limiting Facility Rating to each affected Planning Coordinator and Reliability Coordinator.

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R1.

R2. Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure that System steady-state voltage limits used in its Planning

Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits used in operations per the Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting System Voltage Limits if it provides a technical rationale for using less limiting System Voltage Limits to each affected Transmission Planner and Reliability Coordinator.
- The Transmission Planner may use less limiting System Voltage Limits if it provides a technical rationale for using less limiting System Voltage Limits to each affected Planning Coordinator and Reliability Coordinator.

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R2.

R3. Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria used in operations per the Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting stability performance criteria if it provides a technical rationale for using less limiting stability performance criteria to each affected Transmission Planner and Reliability Coordinator.
- The Transmission Planner may use less limiting stability performance criteria if it provides a technical rationale for using less limiting stability performance criteria to each affected Planning Coordinator and Reliability Coordinator.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R3.

R4. Each Planning Coordinator and each Transmission Planner shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only) to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner, and Generation Owner. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);

4.2 The associated stability criteria used as part of determining the instability;

4.3 The associated Contingency(ies) and any Facilities critical to the instability, Cascading or uncontrolled separation;

4.4 A description of the studied System conditions when the instability, Cascading or uncontrolled separation was identified;

4.5 Any Remedial Action Scheme action, undervoltage load shedding (UVLS) action, underfrequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; and

4.6 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator and Transmission Planner shall keep evidence for Requirements R1 through R4 for the most current year plus the previous three years.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but failed to identify the exclusion criteria allowing the use of less limiting Facility Ratings.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in its Reliability Coordinator's SOL Methodology.
R2.	N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its technical rationale.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.

R3.	N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its technical rationale.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that stability performance criteria used in Planning Assessments are equally limiting or more limiting than the stability performance criteria established in the Reliability Coordinator's SOL Methodology.
R4.	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain one of the elements listed in Requirement R4, Parts 4.1 – 4.6.	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain two of the elements listed in Requirement R4, Parts 4.1 – 4.6.	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain three elements listed in Requirement R4, Parts 4.1 – 4.6.	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain four or more of the elements listed in Requirement R4, Parts 4.1 – 4.6. OR

				The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner and Generator Owner.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1		Project 2015-09 SOL – Adopt new standard.	New

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Glossary Definition: System Operating Limit

Term: "System Operating Limit"

Definition:

Redline

All Facility Ratings, System Voltage Limits, and stability limits, applicable to ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a~~ specified system configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states. ~~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)~~

Clean

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

Introduction

The standard drafting team ("SDT") for *Project 2015-09 Establish and Communicate System Operating Limits* developed these rationales to explain the modifications to the definition of the term "System Operating Limit" ("SOL ") to be incorporated into the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary"). As discussed below, the purpose of the proposed modified term is to provide greater clarity and consistency with the SOL concept and how SOLs work alongside operational performance criteria to result in reliable operations.

Background

The use of SOLs is a foundational concept in NERC's Reliability Standards, as operating within SOLs for the pre- and post-Contingency state is a primary aspect of reliable Bulk Electric System ("BES") operations. An SOL is currently defined in the NERC Glossary as:

> *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)*

SOLs are the primary focus of FAC standards FAC-010, FAC-011, and FAC-014. Per these FAC standards:

- Planning Coordinators are required to have a methodology for establishing SOLs in its area for use in the planning horizon (FAC-010-3)
- Planning Coordinators and Transmission Planners are required to establish SOLs for use in the planning horizon consistent with the Planning Coordinator's SOL Methodology (FAC-014-2)
- Reliability Coordinators are required to have a methodology for establishing SOLs in its area for use in the operations horizon (FAC-011-3)
- TOPs are required to establish SOLs for use in the operations horizon consistent with the Reliability Coordinator's SOL Methodology (FAC-014-2)

FAC-011-3 requirement R2 states that the *"RC's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following."* The subsequent subparts to FAC-011-3 requirement R2 further describe pre-Contingency performance criteria (in R2.1), the post-Contingency performance criteria (in R2.2), and describe other rules related to the establishment of SOLs in the remaining subparts. The language in requirement R2 indicates that the SOLs established in accordance with requirement R2 are expected to "provide" a level of pre- and post-Contingency reliability described in the subparts of requirement R2. Accordingly, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the SOL establishment process, yielding a set of SOLs that "provide" for meeting the performance criteria denoted in FAC-011 R2 and subparts.

Requirements in FAC-014-2 then require the communication of those SOLs to the various operations and planning entities. TOP standards in effect at the time required TOPs to operate within these SOLs.
These FAC standards and related TOP standards established a construct for reliable operations. This SOL construct depicted in the body of Reliability Standards in effect in the 2007 timeframe is characterized by the following:

1. The TOPs and RCs would run studies for expected system conditions where the studies would examine the pre-Contingency state and the post-Contingency state.
2. If any performance criteria (in FAC-011 R2 subparts) were not being met in those studies, the TOP would establish an SOL which, if operated within, would result in all of those performance criteria being met.
3. The TOP would communicate those SOLs to System Operators.
4. The TOP System Operators would operate within those SOLs.

The TOP and IRO standards in effect prior to April 1, 2017 required TOPs to operate within these SOLs, the presumption being that if those SOLs were operated within in Real-time operations, then the acceptable pre- and post-Contingency operations criteria depicted in FAC-011-3 requirement R2 and subparts would be met.

It is important to note that prior to April 1, 2017 there were no Reliability Standards that required operational entities to perform assessments of the post-Contingency state in same-day or Real-time operations. Prior to April 1, 2017, the requirements associated with assessments of the post-Contingency state were folded into SOL establishment process – the establishment of SOLs that "provide" for meeting the documented pre- and post-Contingency performance criteria in FAC-011-3 requirement R2 and subparts.

The definition of SOL and the Reliability Standards that address SOLs – FAC-010, FAC-011, and FAC-014 – have remained essentially unchanged since their initial versions were approved and adopted in 2007. Since that time, many improvements have been made to the body of reliability standards, specifically those in the TPL, TOP, and IRO family of standards. The former TPL-001, -002, -003, and -004 Reliability Standards have been replaced with TPL-001-4, all of the TOP standards were replaced with the currently effective TOP-001, TOP-002, and TOP-003, and several IRO standards have been replaced as well. The definition of SOL and the FAC standards that address SOLs are inextricably linked to many of the TPL, TOP, and IRO standards, as they all address in some manner the foundational reliability concept of acceptable system performance. One of the primary objectives of Project 2015-09 is to make changes to the SOL definition and the related FAC standards to create better alignment with the currently effective TPL, TOP, and IRO standards. The SDT's proposal to revise the definition of SOL improves clarity, reduces redundancy, and creates better alignment and continuity with the currently effective TOP and IRO standards.

Due to changes in the TOP and IRO Reliability Standards that became effective on April 1, 2017, this SOL construct described by the currently effective definition of SOL and the manner in which it is used in the FAC standards is not reflective of the construct encapsulated in the operational requirements in place

today. The new TOP and IRO standards represent a new construct for managing reliability for the pre- and post-Contingency state. Under this new construct approved in Order No. 817[1]:

1. TOPs and RCs are required to ensure that an Operational Planning Analysis (OPA) is performed to assess whether the planned operations for the next-day will exceed any of its SOLs and IROLs[2]. The pre- and post-Contingency states are analyzed as part of the OPA.[3]
2. If the OPA identifies any potential exceedances, the RC and TOP must have an Operating Plan to address the exceedance.[4]
3. In Real-time, RCs and TOPs must perform Real-time Assessments (RTAs) at least once every 30 minutes to determine whether there are any expected or actual exceedances of SOLs (including IROLs) based on Real-time conditions.[5] The pre- and post-Contingency states are analyzed as part of the RTA.[6]
4. If SOL exceedances are observed in TOP Real-time monitoring or RTAs, TOPs are required to implement its Operating plan to mitigate the conditions.[7]
5. If SOL or IROL exceedances are observed in RC Real-time monitoring or RTAs, RCs are required to notify TOPs of those exceedances.[8]
6. If there is an expected or actual IROL exceedance identified in RC Real-time monitoring or RTAs, the exceedance must be resolved within the IROL T_v, which can be no longer than 30 minutes.[9]

Pursuant to the construct in the currently-effective TOP/IRO Reliability Standards, TOPs and RCs must assess system conditions, identify expected or actual SOL exceedances (including for the subset of SOLs designated as IROLs) and take steps to address any such exceedances to avoid the possibility of further deterioration in system conditions. Under this new construct, the pre- and post-Contingency states are assessed on an ongoing basis as part of OPAs and RTAs. Any SOL exceedances that are observed are required to be mitigated per the respective Operating Plans. Under this new construct, it is the OPA, the RTA, and the implementation of Operating Plans that "provide" for reliable pre- and post-Contingency operations. In the former construct, operating within the TOP-provided SOL "provided" for reliable pre- and post-Contingency

[1] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 (2015).

[2] IRO-008-2, Requirement R1; TOP-004-2, Requirement R1.

[3] OPA – 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.)

[4] IRO-008-2, Requirement R2; TOP-004-2, Requirement R2.

[5] IRO-008-2, Requirement R4; TOP-001-3, Requirement R13.

[6] RTA – 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.)

[7] TOP-001-3 requirement, Requirement R14

[8] IRO-008-2 requirement, Requirement R5

[9] IRO-009-2, Requirements R1-R4; TOP-001-3, Requirement R12.

operations. The proposed revised FAC standards and the proposed revised SOL definition is intended to reflect the new construct depicted in the TOP and IRO standards.

NERC SOL Whitepaper

As discussed in the whitepaper prepared by the SDT for Project 2014-03 Revisions to TOP and IRO Standards (the "Project 2014-03 Whitepaper"), which developed the currently-effective Transmission Operations ("TOP") and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards, while the term SOL is used extensively in the NERC Reliability Standards, there is significant confusion with, and many widely varied interpretations and applications of, the term SOL. While the Project 2014-03 SDT did not seek to modify the SOL definition, they drafted the Project 2014-03 Whitepaper to describe their understanding of the SOL term/concept and to "bring clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances." The Project 2014-03 Whitepaper served as the conceptual basis for the development of the currently-effective TOP/IRO Reliability Standards.

As described in the Project 2014-03 Whitepaper, the central principles of the SOL concept in NERC's Reliability Standards is to:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

These principles are reflective of the new construct for managing reliability for the pre- and post-Contingency state depicted in the TOP and IRO standards created as part of Project 2014-03.

Following the development of the currently-effective TOP/IRO Reliability Standards, NERC initiated a periodic review of the requirements in the Facilities Design, Connections, and Maintenance ("FAC") group of Reliability Standards addressing SOLs. The periodic review team identified a need to revise or develop new definitions to be incorporated into the NERC Glossary to provide greater clarity and consistency in establishing SOLs and promote a common understanding of what it means to exceed SOLs. The periodic review team recognized that while the project 2014-03 Whitepaper provided clarity on the SOL concept, reliability would be further enhanced by (1) revising the SOL definition in the NERC Glossary, and (2) developing a new defined term SOL Exceedance. The periodic review envisioned that these two enhancements help to better align the definitions in the NERC Glossary with the Project 2014-03 Whitepaper and better support the SOL exceedance concept used in the TOP/IRO Reliability Standards. Subsequently, to address the issues identified in the periodic review, NERC initiated Project 2015-09 to revise the requirements for, and definitions related to, the methodology used for establishing and communicating SOLs.

In September of 2017 the standard drafting team posted a proposed definition of SOL Exceedance for informal comment. The industry responses to the draft SOL Exceedance definition indicated numerous significant concerns. Given these responses, the SDT concluded that creating a definition of SOL Exceedance that adequately reflected reliable operating principles could create too much of an unnecessary compliance burden without significant modification to the existing TOP and IRO standards. Therefore, the SDT

abandoned the idea of creating a definition for SOL Exceedance in favor of addressing the performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the way it is done in the currently effective FAC standards.

Modifications to SOL Definition

The Project 2015-09 SDT proposes to define the term System Operating Limit (SOL) as:

> *All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.*

The SDT's intent was to simplify and clarify the SOL definition by eliminating ambiguities such that SOLs are easily identifiable and easily measurable. The currently-effective SOL definition states that SOLs "are based upon certain operating criteria." The modified definition eliminates the phrase "are based upon" to more accurately state that the SOLs "are" the actual operating parameters which are to be observed for the pre- and post-Contingency states, leaving no confusion as whether a Facility Rating, stability limit, or voltage limit is an SOL. The unambiguous language in the modified definition should help facilitate a more consistent application of the SOL concept within the electric industry.

Facility Ratings, System Voltage Limits, and stability limits are the three types of operating criteria included in the existing SOL definition and carried forward into the modified definition that must be accounted for to ensure reliable operations. Facility Ratings must be established in accordance with Reliability Standard FAC-008-3. System Voltage Limits, as discussed below, is proposed to be defined as "the maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance." Stability limits includes both transient stability limits and voltage stability limits. The intent of using the "stability limit" term (as opposed to the NERC Glossary term "Stability Limit") is to allow for a number of different types of stability-related limitations or phenomena, including, but not limited to, sub-synchronous resonance (SSR), phase angle limitations, transient voltage limitations on equipment, and weighted short-circuit ratio (WSCR). The Glossary term "Stability Limits" is not appropriate for use in the revised definition because its use is limited to a maximum power flow value. While some entities may use maximum power flow values as a means by which to prevent instability, this approach represents only one particular method and may be too restrictive for some entities. Reliability tools allow entities to monitor and control parameters other than maximum power flow values in order to demonstrate acceptable stability performance.

Unlike the existing SOL definition, the proposed definition includes the phrase "used in Bulk Electric System operations" to distinguish those Facility Ratings, voltage limits, and stability limits that are used in planning. The SDT determined that the SOL concept should be limited to the operational time horizon and thus proposes to retire FAC-010-3. The Facility Ratings, voltage limits, and stability criteria used in the planning horizon are developed according to FAC-008-3 and TPL-001-4 and, as a result, there was no additional reliability need to require Planning Authorities to develop SOLs to be used in the planning horizon. The SDT concluded, however, that there was a reliability need to coordinate the Facility Ratings, voltage limits, and

stability criteria used in planning with those used in operations. The SDT developed proposed Reliability Standard FAC-015-1 to address that issue.

As discussed in detail below, the SDT determined that references to "most limiting criteria" and "acceptable reliability criteria", and the manner in which the "specified system configuration" and the "pre- and post-contingency" phrases were used in the currently-effective definition of SOL were adding to industry confusion as to what constitutes an SOL.

Most limiting Criteria – The SDT concluded that removing the "most limiting criteria" concept in favor of designating all Facility Ratings, System Voltage Limits, and stability limits as SOLs is better aligned with the requirements in the TOP/IRO Reliability Standards. As noted above, under the TOP/IRO Reliability Standards, each RC and TOP must perform Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) to assess conditions in the day ahead and Real-time horizon and, if it identifies any actual, expected or potential SOL exceedance, take appropriate mitigating action to maintain pre- and post-Contingency reliable operations. Under the currently-effective SOL definition, RCs and TOPs must initially determine which operating parameter is the most limiting at that point in time to be designated as the SOL and then determine if there are any actual, potential, or expected exceedances of that SOL. The SDT understands that this has caused some confusion within industry. Specifically, it may be unclear in Real-time operations when an SOL ceases to be an SOL because it is no longer the "most limiting criteria." Confusion is introduced when the most limiting criteria (and thus the SOL) changes from one RTA to the next.

The SDT determined that it is more straightforward to simply categorize all Facility Ratings, System Voltage Limits, and stability limits as SOLs. In performing OPAs and RTAs, RCs and TOPs should be assessing conditions as it relates to any operating parameter or reliability limit, not the most limiting parameter or limit based on a particular prior analysis. Under the new TOP and IRO requirements, RCs and TOPs are assessing conditions on an ongoing basis through OPAs and RTAs to determine whether there are any actual, potential, or expected exceedances of any Facility Rating, System Voltage Limit, or stability limit, which would necessarily include the most limiting of those parameters/limits. In this manner, the "most limiting criteria" concept is subsumed within the requirements of the TOP/IRO Reliability Standards and it is not necessary that it be included in the SOL definition. In short, the proposed SOL definition creates a simplified approach. There is no need to continuously identify and communicate the ever-changing "most limiting" criteria. Entities must simply operate – and plan to operate – to prevent any exceedance of all Facility Ratings, System Voltage Limits, and stability limits.

The SDT determined that the removal of the "most limiting criteria" from the SOL definition represents an improvement to reliability. The "most limiting criteria" can adversely impact reliability by masking instability risks that may exist slightly beyond the point of the most limiting condition. To illustrate, where prior studies indicate that a thermal limitation is the "most limiting criteria," if the studying entity does not study the performance of the system appreciably beyond this thermal limitation to reasonably expected stressed conditions, it cannot be safely concluded that a more significant instability risk does not exist slightly beyond the point where the "most limiting criteria" exists. Because actions may be taken in the actual system conditions that mitigate thermal and voltage limitations identified as a "most limiting criteria", it may be necessary to identify where subsequent operation may approach a point of instability. Consistent with this

concept, the RC and its TOPs have the responsibility of establishing stability limits in accordance with the Reliability Coordinator's SOL Methodology, as required by FAC-011-4 Requirement R4 and FAC-014-3 Requirements R2 and R4.

Acceptable Reliability Criteria – The SDT determined that the "acceptable reliability criteria" concept is best addressed through requirement language and that the SOL definition should focus simply on what constitutes an SOL. Taken together, the operations performance criteria in FAC-011-4 requirement R6 and the corresponding requirement R7 in FAC-014-3 adequately addresses operation within acceptable reliability criteria.

Specified System Configuration – The SDT proposes to retain the reference to "specified system configuration" due to the fact that stability limits in particular are typically dependent on system configuration. While Facility Ratings and System Voltage Limits are not typically dependent upon system configuration, there may be times where they may be dependent on System configuration. For example, if a transmission line is connected by two circuit breakers at one end of the line, and one of those two circuit breakers is open, the value of the Facility Rating for line could be reduced due to current carrying capability of the remaining in-service circuit breaker.

Pre- and Post-Contingency – The currently effective SOL definition specifies that each of the listed operating limit types are applicable for both the pre- and post-Contingency states. The SDT determined that the pre- and post-Contingency concept needed to be retained; however, it should be used in a manner consistent with the construct depicted in the new TOP and IRO standards rather than the old construct where the SOL itself "provided" for pre- and post-Contingency acceptable performance. The proposed definition makes it clear that both the pre-Contingency state and the post-Contingency state must be considered when evaluating the System performance for Facility Ratings, System Voltage Limits, and stability limits. As OPAs and RTAs are the mechanisms in the Reliability Standards for determining potential SOL exceedances (OPA) and actual SOL exceedances (RTA),[10] the definition of SOL should support the concept that both the pre- and post-Contingency states should be accounted for.

One aspect of the improved clarity of the revised definition of SOL is seen in its intended use. Under the revised definition, SOLs are intended to be used as an input into the OPA and RTA process.[11] The OPA and RTA process itself examines SOLs for the pre- and post-Contingency states and determines whether the SOLs are being exceeded. Accordingly, while SOLs are an input to the OPA and RTA process, SOL exceedance is the output of the OPA and RTA process. FAC-014-3 requirement R7 effectively stipulates that the operations performance criteria denoted in FAC-011-4 requirement R6 must be used in OPAs, RTAs, and Real-time monitoring when identifying SOL exceedances.

[10] In Order No. 705 (at P 162), the Commission stated that system performance is determined through studies, stating "the Commission believes that to demonstrate the pre- and post-contingency performance metrics required by [FAC-010-1] Requirements R2.1-R2.2 an assessment or analysis would need to be performed. As such, Requirements R2.1-R2.2 provide for actions that go beyond NERC's characterization of the subject of the requirements as limited to a list of topics that must be included in a methodology. Therefore, we conclude that these Requirements are more Docket No. RM07-3-000 - 79 - properly treated as implementation or operational requirements that may have a direct impact on reliability."

[11] Some Reliability Coordinators and Transmission Operators may establish stability limits in the context of an OPA or RTA. For entities who adopt this approach, the stability SOL would be established – and its exceedance determined – as part of the OPA or RTA.

Lastly, as with the currently-effective SOL definition, the proposed SOL definition does not include reference to IROLs. IROLs, as currently defined, are a subset of SOLs that, if exceeded, "could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the BES." The determination of when an SOL should be designated as an IROL is most appropriately addressed in the RC's SOL methodology. There is no need to mention IROLs in the definition of SOL.

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. Title: Physical Security

2. Number: CIP-014-32

3. Purpose: To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

4.1.1.2 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by the ~~its Reliability Coordinator,~~ Planning Coordinator~~,~~ or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ~~as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies~~.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates:

See Implementation Plan for CIP-014-32.

6. Background:

~~This~~ Reliability Standard CIP-014-2 addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of

such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be

developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.

- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or

- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

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 during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three 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, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner's and Transmission Operator's facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**High**	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an	or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an	result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection	stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months;

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			less than or equal to 100 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed	following completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			operates the primary control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identification in Requirement R1.
R4	**Operations Planning, Long-term Planning**	**Medium**	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						primary control center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
R6	**Long-term Planning**	**Medium**	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	Requirement R4 and the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	October 1, 2015	Effective Date	New
2	April 16, 2015	Revised to meet FERC Order 802 directive to remove “widespread”.	Revision
2	May 7, 2015	Adopted by the NERC Board of Trustees	
2	July 14, 2015	FERC Letter Order in Docket No. RD15-4-000 approving CIP-014-2	

Guidelines and Technical Basis

Section 4 Applicability

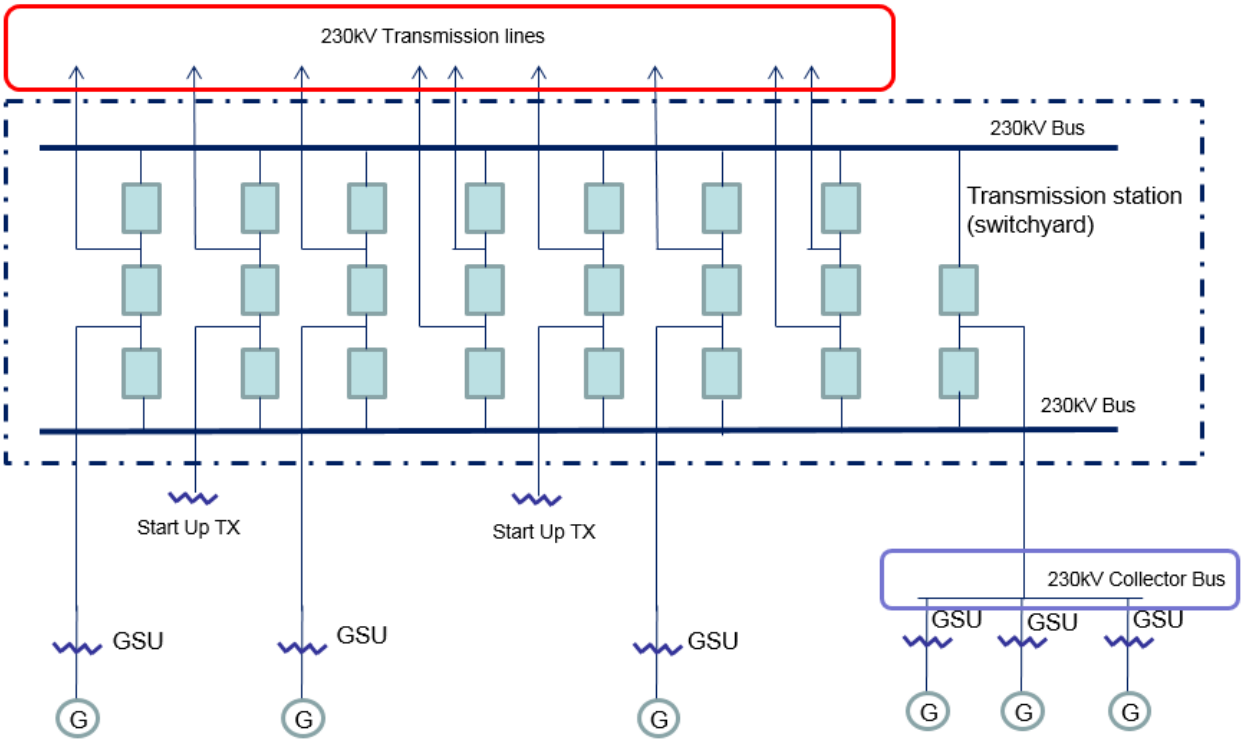
The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014 first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (*i.e.*, those that could cause instability, uncontrolled separation, or Cascading within an

Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in ~~exceeding one or more Interconnection Reliability Operating Limits (IROLs)~~instability, uncontrolled separation, or Cascading. The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase "Transmission stations or Transmission substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014 standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the

Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

Performing Risk Assessments

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential instability, uncontrolled separation, or Cascading within an Interconnection. Regional consultation on these matters is likely to be

helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center "operationally controls" a Transmission station or Transmission substation when the control

center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2 is to have an entity other than the owner or operator of the facility to be involved in the risk

assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only "need to know" employees, etc., get the information.
3. Marking documents as confidential
4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.
- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.
- ASIS International Facilities Physical Security Measure Guideline.

- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

  Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

  A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various

sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

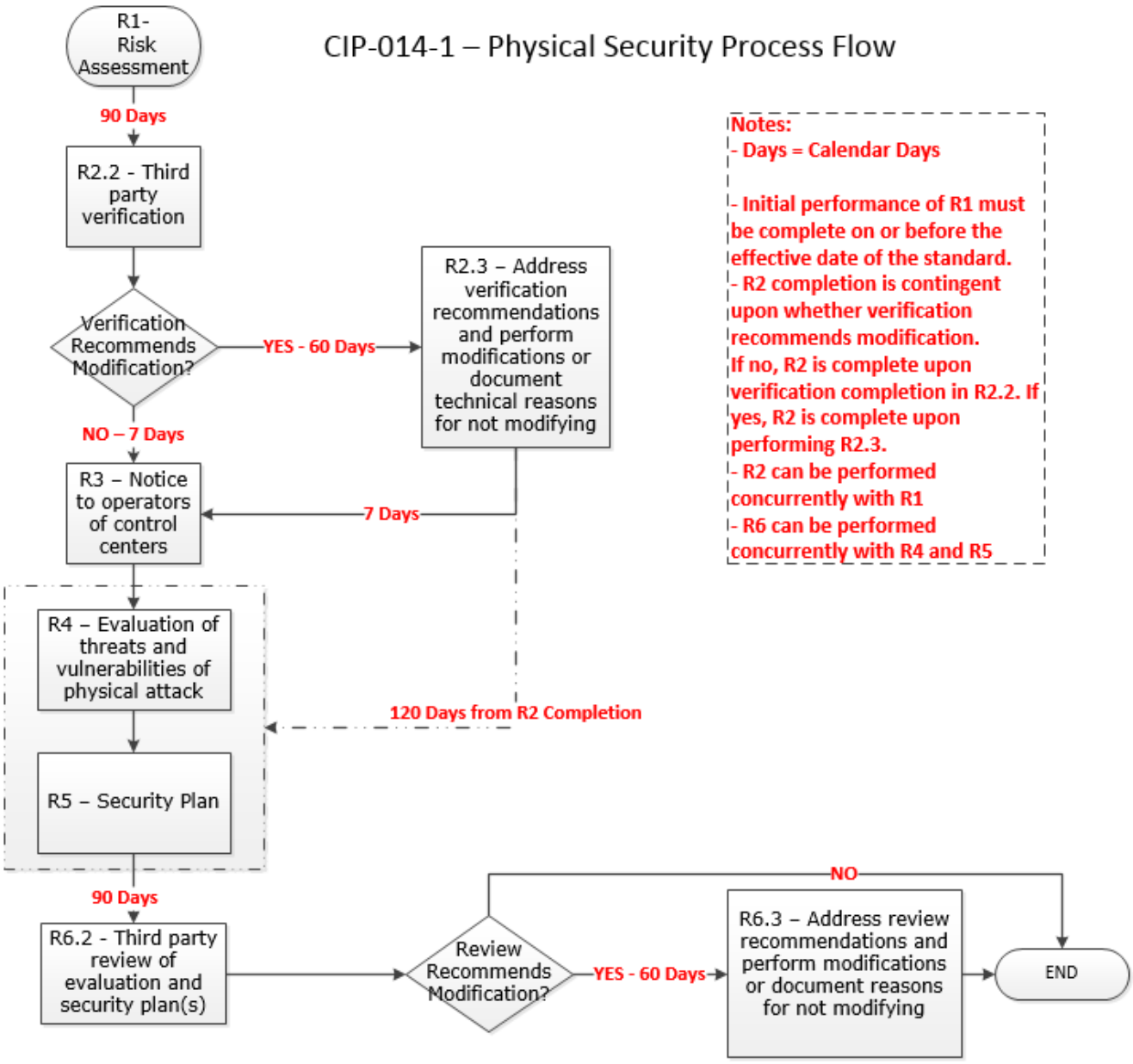
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

- *An entity or organization approved by the ERO.*
- *A governmental agency with physical security expertise.*
- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
R3 – Notice to operators of control centers
7 Days
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
YES - 60 Days
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
NO
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification. If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

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:
This requirement meets the FERC directive from paragraph 6 of its March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through instability, uncontrolled separation, or cascading failures. The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

Requirement R1 also meets the FERC directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

Rationale for Requirement R2:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term "unaffiliated" means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term "unaffiliated" is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

Rationale for Requirement R3:
Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

Rationale for Requirement R4:
This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security

plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

Rationale for Requirement R5:
This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Rationale for Requirement R6:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-54

3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Applicable Transmission Owners

   4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

   4.1.2. Applicable Generator Owners

   4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

   4.2. Transmission Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

   4.2.1. Each overhead transmission line operated at 200kV or higher.

   4.2.2. Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.~~identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.~~

   4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major Western Electricity Coordinating Council (WECC) Transfer Path in the Bulk Electric System by WECC.

   4.2.4. Each overhead transmission line identified above (4.2.1. through 4.2.3.) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

4.3. Generation Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities:

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV and are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.~~identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator~~; or

4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

5. Effective Date: See Implementation Plan

6. Background: This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

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 bulk power system performance 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*

[2] *Id.*

[3] "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

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 defense-in-depth strategy for Rreliability Sstandards development recognizes that each requirement in a NERC Rreliability Sstandard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability Sstandards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a Rreliability Sstandard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Requirement R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. Requirements R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. Requirement R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). Requirement R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s), ~~which are either an element of an IROL, or an element of a Major WECC Transfer Path;~~ operating within their Rating and all

Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

1.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. [Reserved for future use] ~~Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[9] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:~~

~~**2.1.** An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,[10]~~

[4] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this R~~r~~eliability S~~s~~tandard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

[5] If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

[7] *Id.*

[8] *Id.*

~~[9] See footnote 4.~~

~~[10] See footnote 5.~~

~~2.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[11]~~

~~2.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[12]~~

~~2.4.~~2.1. ~~An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]~~

M2. [Reserved for future use] ~~Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)~~

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

3.1. Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

3.2. Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the

~~[11] See footnote 6.~~
~~[12] *Id.*~~

~~[13] *Id.*~~

associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When an applicable Transmission Owner and an applicable Generator Owner are constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[14] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).

[14] When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[15]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

M7. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

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.

[15] Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

  A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of instability,

Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, by vegetation inside and/or outside of the ROW;

- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lostor degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are epected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, blowing together from within the ROW;
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per

the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ~~as an element of an IROL or Major WECC transfer path~~ and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ~~as an element of an IROL or Major WECC transfer path~~ and a vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW*

				• *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R2.			~~The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4 Table 2 was observed in real time absent a Sustained Outage.~~	~~The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:~~ • ~~*A fall-in from inside the active transmission line ROW*~~ • ~~*Blowing together of applicable lines and vegetation located inside the active transmission line ROW*~~ • ~~*A grow-in*~~
R3.		The responsible entity has maintenance strategies or documented procedures or	The responsible entity has maintenance strategies or documented procedures or	The responsible entity does not have any maintenance strategies or documented

		processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2.)	processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1.)	procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice

	line, line miles or kilometers, etc.)	units of choice - circuit, pole line, line miles or kilometers, etc.).	units of choice - circuit, pole line, line miles or kilometers, etc.).	- circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	1. Added “Standard Development Roadmap.” 2. Changed “60” to “Sixty” in section A, 5.2. 3. Added “Proposed Effective Date: April 7, 2006” to footer. 4. Added “Draft 3: November 17, 2005” to footer.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New

2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[16]	Revisions
2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions

[16] *Revisions to Reliability Standard for Transmission Vegetation Management, Order No. 777,* 142 FERC ¶ 61,208 (2013)

4	February 11, 2016	Adopted by Board of Trustees. Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions
4	March 9, 2016	Corrected subpart 7.10 to M7, corrected value of .07 to .7	Errata
4	April 26, 2016	FERC Letter Order approving FAC-003-4. Docket No. RD16-4-000.	

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[17]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[18]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[19]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

[17] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[18] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[19] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[20]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[21]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268 m up to 4572 m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[22]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

[20] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[21] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[22] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

[+] Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[23]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	MVCD meters Over sea level up to 500 ft (Over sea level up to 152.4 m)	MVCD meters Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	MVCD meters Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	MVCD meters Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	MVCD meters Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	MVCD meters Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	MVCD meters Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	MVCD meters Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	MVCD meters Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	MVCD meters Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	MVCD meters Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	MVCD meters Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

[23] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case is needed because the Planning Coordinators may designate lines below 200 kV-, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, ~~to become elements of an IROL or Major WECC Transfer Path~~ in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. A line operating below 200kV designated by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ~~as an element of an IROL or Major WECC Transfer Path~~ may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Date that Planning Study is completed	PY the line will become an ~~IROL~~ identified element	Date 1	Date 2	Effective Date The later of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Defined Terms:

Explanation for revising the definition of ROW:

The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the current definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspection:
The current glossary definition of this NERC term was modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the derivation of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet equation. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 of the ~~S~~standard provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No.

RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1 and R2:

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element ~~of an IROL or Major WECC Transfer Path~~by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation. R2 is applicable to all other lines that are not identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~pursuant to FAC-015-1 Requirement R4elements of IROLs, and not elements of Major WECC Transfer Paths~~.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line has been identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lostor degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~that is an element of an IROL or a Major WECC Transfer Path~~ is a greater risk to the interconnected electric transmission system than applicable lines that ~~are not elements of IROLs or Major WECC Transfer Paths~~have not been identified as such. Applicable lines that ~~are not elements of IROLs or Major WECC Transfer Paths~~have not been identified as such do require effective vegetation management, but these lines are comparatively less operationally significant.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations. These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence

of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3:
R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.

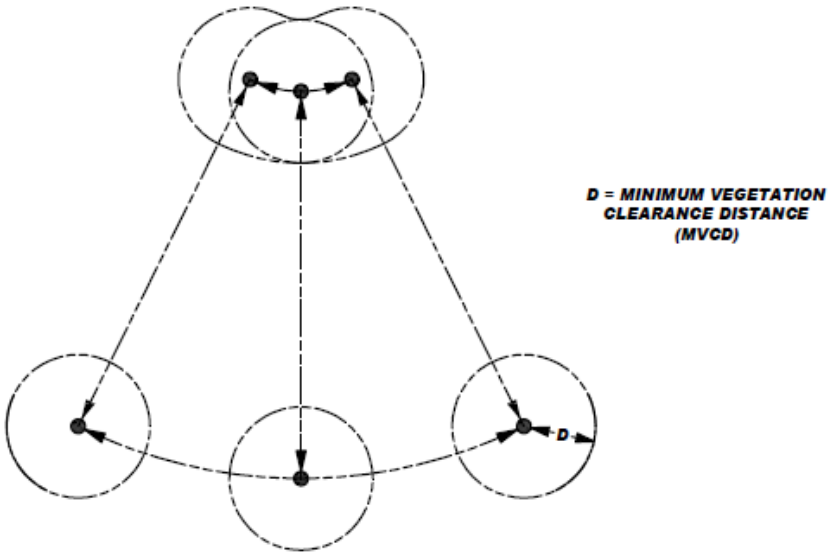


Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:
R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:
R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of herbicides to control incompatible vegetation outside of the MVCD, but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.

- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation

management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

When an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner's or applicable Generator Owner's annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If an applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.
In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be

documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 used the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-1 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is

still present. The intent of FAC-003 is to keep a transmission line that is in service from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line was approximately 2.0 per unit. This value was a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below was considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit was considered a realistic maximum.

The Gallet equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs.

IEEE 516-2003 MAID distances

(AC) Nom System Voltage (kV)	**(AC) Max System Voltage (kV)**	**Transient Over-voltage Factor (T)**	**Clearance (ft.) Gallet (wet) @ Alt. 3000 feet**	Table 7 (Table D.5 for feet) **IEEE 516-2003 MAID (ft) @ Alt. 3000 feet**
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

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 Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event.
2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment.
3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Rationale for Applicability (section 4.3):
Within the text of NERC Reliability Standard FAC-003-3, "transmission line(s)" and "applicable line(s)" can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Rationale for R1 ~~and R2~~:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the

applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

Rationale for R6:

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16
45-day formal comment period with initial ballot	09/29/17 – 11/14/17

Anticipated Actions	Date
45-day formal comment period with additional ballot	August 2018 – October 2018
10-day final ballot	October 2018
NERC Board adoption	November 2018

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:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

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

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

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

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R2.

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

3.1. Require that each BES bus~~es~~/station~~s~~ have an associated System Voltage Limit, unless ~~except for~~ the Reliability Coordinators SOL Methodology specifically allows the exclusion of BES buses/stations ~~that may be excluded as specified in the Reliability Coordinator's SOL Methodology~~from the requirement to have an associated System Voltage Limit;

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

3.3. Require that System Voltage Limits are ~~higher~~greater than or equal to in-service relay settings for under voltage load shedding ~~(UVLS) relay settings~~systems and Undervoltage Load Shedding Programs;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. ~~Address~~Require ~~-~~the use of common System Voltage Limits between the ~~Reliability Coordinator and the~~ Transmission ~~Operators in~~Operator and its Reliability Coordinator ~~Area~~ and provide the method for determining the common System Voltage Limits to be used in operations;

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

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

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

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

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. ~~angular~~unit stability; and

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5.

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

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

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

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations. ~~;~~

~~4.6.~~4.7. State that the ~~planned~~ use of underfrequency load shedding (UFLS) ~~is~~programs and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits.

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

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

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

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

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

5.2. ~~Any~~Identify any additional single or multiple Contingency events or types of ~~single~~ Contingency events ~~identified~~for use in performing Operational Planning Analysis and Real-time Assessments.

~~5.2.~~5.3. Identify any additional single or multiple Contingency events or types of Contingency events for use in determining stability limits~~, or for use in performing OPAs and RTAs.~~.

~~**5.3.** Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.~~

5.4. ~~The method for considering~~Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-015-1, Requirement ~~R6 to identify the Contingencies for~~R4, to use in determining stability limits.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include in its SOL Methodology, at a minimum, the following Bulk Electric System performance criteria: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. The actual pre-Contingency state (Real-time monitoring and Real-time Assessment) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

6.1.1. Flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Instability, Cascading or uncontrolled separation do not occur.

6.2. The evaluation of potential single Contingencies listed in Part 5.1.1 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

6.2.1. Flow through Facilities are within applicable Emergency Ratings, provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings. Flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Voltages are within emergency System Voltage Limits.

6.2.3. Instability, Cascading or uncontrolled separation do not occur.

6.3. The evaluation of the potential Contingencies identified in Part 5.2 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates that instability, Cascading, or uncontrolled separation does not occur.

6.4. The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur.

6.5. In determining the System's response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding is acceptable only after all other available System adjustments have been made.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R6.

~~R6.~~R7. Each Reliability Coordinator shall include in its SOL Methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

~~6.1.~~7.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

~~6.2.~~7.2. Criteria for determining when violating a SOL qualifies as an IROL and criteria for developing any associated IROL T_V.

~~M6.~~M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R6.

~~R7.~~R8. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate their established SOLs ~~it established~~ to the ~~its~~ Reliability Coordinator~~(s)~~. The method shall address the periodicity for communicating established~~of~~ SOLs ~~communication~~. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~M7.~~M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R7.

~~R8.~~R9. Each Reliability Coordinator shall provide its SOL Methodology ~~and any changes to the SOL Methodology prior to the effective date of the SOL Methodology,~~ to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

~~8.1.~~9.1. Each~~Each adjacent Reliability Coordinator within an Interconnection, and each~~ Reliability Coordinator that requests and indicates it has a reliability-related need~~;~~ within 30 days of a request.

9.2. Each of the following entities prior to the effective date of the SOL methodology:

9.2.1. Each adjacent Reliability Coordinator within the same~~an~~ Interconnection;

~~8.1.1.~~9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

~~8.1.2.~~9.2.3. Each Transmission Operator within its Reliability Coordinator Area~~.~~; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

~~M8.~~M9. Acceptable evidence that the Reliability Coordinator provided its SOL Methodology to the entities identified in Requirement R8 may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts,

registered mail receipts, or postings to a secure web site with accompanying notification(s).

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator shall keep data or evidence of compliance with Requirements R1 through ~~R8~~R9 for the current year plus the previous 12 calendar months. .

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.
R2.	N/A	N/A	The Reliability Coordinator included in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations, but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.
R3.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of

				Requirement R3 into its SOL Methodology.
R4.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL Methodology.
R5.	N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL Methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3, and 5.4 of Requirement R5 into its SOL Methodology.
R6.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL Methodology.
~~R6~~R7.	N/A	N/A	The Reliability Coordinator failed to include Part ~~6~~7.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology.	The Reliability Coordinator failed to include Parts ~~6~~7.1 and ~~6~~7.2 in its SOL Methodology.

			OR The Reliability Coordinator failed to include Part ~~6~~7.2 (a criteria for determining when violating a SOL qualifies as an IROL in its SOL Methodology. OR The Reliability Coordinator failed to include Part ~~6~~7.2 (criteria for developing any associated IROL T_v) in its SOL Methodology.	
~~R7~~R8.	N/A	N/A	The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the Transmission Operator established.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the periodicity of SOL communication.
~~R8~~R9.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR	The Reliability Coordinator failed to provide its new or revised SOL Methodology to two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR	The Reliability Coordinator failed to provide its new or revised SOL Methodology to ~~one~~three of the parties specified in ~~Parts 8.1 through 8.3.~~Requirement	The Reliability Coordinator failed to provide its new or revised SOL Methodology to ~~two~~four or more of the parties specified in ~~Parts 8.1 through 8.3.~~Requirement

	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part ~~8.4~~9.1 but was late by less than or equal to 10 calendar days.	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part ~~8.4~~9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part ~~8.4~~9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	R9, Part 9.2 prior to the effective date OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the parties specified in ~~Parts 8.1 through 8.3 prior to the effective date of the SOL Methodology.~~Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part ~~8.4~~9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part ~~8.4~~9.1.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board ~~of Trustees~~	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board ~~of Trustees~~: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board ~~of Trustees~~ for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
3	November 13, 2014	Adopted by the NERC Board ~~of Trustees~~	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4		Project 2015-09 – Adopt revisions to standard.	Revisions

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon

2. **Number:** FAC-013-32

3. **Purpose:** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.

4. **Applicability:**

   4.1. Planning Coordinators

5. **Effective Date:**

See Implementation Plan for FAC-013-3.

B. Requirements and Measures

R1. Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). The Transfer Capability methodology shall include, at a minimum, the following information: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Criteria for the selection of the transfers to be assessed.

1.2. Reserved for future use~~A statement that the assessment shall respect known System Operating Limits (SOLs)~~.

1.3. A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's Planning~~planning~~ Assessments~~practices~~.

1.4. A description of how each of the following assumptions and criteria used in performing the assessment are addressed:

1.4.1. Generation dispatch, including but not limited to long term planned outages, additions and retirements.

1.4.2. Transmission system topology, including but not limited to long term planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected Transmission uses.

1.4.5. Parallel path (loop flow) adjustments.

1.4.6. Contingencies

1.4.7. Monitored Facilities.

1.5. A description of how simulations of transfers are performed through the adjustment of generation, Load or both.

M1. Each Planning Coordinator shall have a Transfer Capability methodology that includes the information specified in Requirement R1.

R2. Each Planning Coordinator shall issue its Transfer Capability methodology, and any revisions to the Transfer Capability methodology, to the following entities subject to the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. Distribute to the following prior to the effectiveness of such revisions:

2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's Planning Coordinator area or overlapping the Planning Coordinator's area.

2.1.2. Each Transmission Planner within the Planning Coordinator's Planning Coordinator area.

2.2. Distribute to each functional entity that has a reliability-related need for the Transfer Capability methodology and submits a request for that methodology within 30 calendar days of receiving that written request.

M2. Each Planning Coordinator shall have evidence such as dated e-mail or dated transmittal letters that it provided the new or revised Transfer Capability methodology in accordance with Requirement R2

R3. If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why. *[Violation Risk Factor: Lower][Time Horizon: Long-term Planning]* (Retirement approved by FERC effective January 21, 2014.)

M3. Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3. (Retirement approved by FERC effective January 21, 2014.)

R4. During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability methodology for at least one year in the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall have evidence such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability methodology pursuant to Requirement R2, Parts 2.1 and Part 2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment available to the entities in accordance with Requirement R5

R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M6. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Planning Coordinator shall have its current Transfer Capability methodology and any prior versions of the Transfer Capability methodology that were in force since the last compliance audit to show compliance with Requirement R1.
- The Planning Coordinator shall retain evidence since its last compliance audit to show compliance with Requirement R2.
- The Planning Coordinator shall retain evidence to show compliance with Requirements R3, R4, R5 and R6 for the most recent assessment. (R3 retired-Retirement approved by FERC effective January 21, 2014.)
- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and 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.
Complaints

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator has a Transfer Capability methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology: • Part 1.1 • ~~Part 1.2~~ • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address three of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate two of the following Parts of Requirement R1 into that methodology: • Part 1.1 • ~~Part 1.2~~ • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address four of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator did not have a Transfer Capability methodology. OR The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate three or more of the following Parts of Requirement R1 into that methodology: • Part 1.1 • ~~Part 1.2~~ • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided the transfer Capability methodology more than 30 calendar days but not more than 60 calendar days after the receipt of a request.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 60 calendar days but not more than 90 calendar days after receipt of a request	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 60 calendar days, but not more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 90 calendar days but not more than 120 calendar days after receipt of a request.	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 120 calendar days after receipt of a request.
R3. (Retirement approved by FERC effective	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability methodology as required in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
January 21, 2013.)	R3 more than 45 calendar days, but not more than 60 calendar days after receipt of the concern.	R3 more than 60 calendar days, but not more than 75 calendar days after receipt of the concern.	R3 more than 75 calendar days, but not more than 90 calendar days after receipt of the concern.	Requirement R3 by more than 90 calendar days after receipt of the concern. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability methodology.
R4.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.	The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90 calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.
R5.	The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its	The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	recipients of its Transfer Capability methodology more than 45 calendar days after the requirements of R5,, but not more than 60 calendar days after completion of the assessment.	Transfer Capability methodology more than 60 calendar days after the requirements of R5, but not more than 75 calendar days after completion of the assessment.	Transfer Capability methodology more than 75 calendar days after the requirements of R5, but not more than 90 days after completion of the assessment.	the recipients of its Transfer Capability methodology more than 90 days after the requirements of R5. OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability methodology under the requirements of R5.
R6.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days after receipt of the request for data, but not more than 60 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 60 calendar days after receipt of the request for data, but not more than 75 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days after receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data. OR The Planning Coordinator failed to provide the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				requested data as required in Requirement R6.

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	08/01/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Lower cased the word "draft" and "drafting team" where appropriate. 3. Changed Anticipated Action #5, page 1, from "30-day" to "Thirty-day." Added or removed "periods."	01/20/05
2	01/24/11	Approved by BOT	
2	11/17/11	FERC Order issued approving FAC-013-2	
2	05/17/12	FERC Order issued directing the VRF's for Requirements R1. and R4. be changed from "Lower" to "Medium." FERC Order issued correcting the High and Severe VSL language for R1.	
2	02/7/13	R3 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	11/21/13	R3 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption, the text from the rationale text boxes was moved to this section.

Rationale for R1:
Text, text, text

Rationale for R2:
Text, text, text

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16
45-day formal comment period with ballot	09/29/17 – 11/14/17

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

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 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

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation ~~to demonstrate~~ that demonstrates the Reliability Coordinator established IROLs in accordance with it SOL Methodology.

R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation ~~to demonstrate~~ that demonstrates the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL Methodology.

R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation ~~to demonstrate~~ that demonstrates the Transmission Operator provided its SOLs in accordance with its Reliability Coordinator's SOL Methodology.

R4. Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability

Coordinator Area in accordance with its SOL Methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation ~~to demonstrate~~ that demonstrates the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2 Each impacted Planning Coordinator within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the ~~derivation of the~~ stability limit or IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated Contingency(ies);

5.2.5 A description of the associated system conditions; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation ~~to demonstrate that~~, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

R6. Each Transmission Operator and Reliability Coordinator ~~that is impacted by an IROL~~ shall ~~provide Transmission Owners and Generation Owners within its~~ use the Bulk Electric System performance criteria specified in the Reliability ~~Coordinator Area a list of Facilities owned by that entity that are critical~~Coordinator's SOL Methodology when performing OPAs, RTAs, and Real-time monitoring to ~~the derivation of the IROL.~~determine SOL exceedances. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation ~~to demonstrate~~, that demonstrates the Transmission Operator and Reliability Coordinator ~~provided~~used the ~~list of Facilities~~Bulk Electric System performance criteria specified in ~~accordance with Requirement R6~~the Reliability Coordinator's SOL methodology when performing OPAs, RTAs and Real-Time Monitoring.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator or Transmission Operator shall keep data or evidence of Requirements R1 through ~~R6~~R8 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be

used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator ~~did not~~failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.
R2.	N/A	N/A	N/A	The Transmission Operator ~~did not~~failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.
R3.	N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but ~~did not~~failed to provide its SOLs at the periodicity at which the RC needs such	The Transmission Operator ~~did not~~failed to provide its SOLs to its Reliability Coordinator.

			information to perform its reliability functions.	
R4.	N/A	N/A	N/A	The Reliability Coordinator ~~did not~~failed to determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.
R5.	The Reliability Coordinator ~~did not~~failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.	The Reliability Coordinator ~~did not~~failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.	The Reliability Coordinator ~~did not~~failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.	The Reliability Coordinator ~~did not~~failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.
R6.	N/A	N/A	N/A	~~The Reliability Coordinator with an established IROL, or the Reliability Coordinator impacted by a neighboring Reliability Coordinator IROL, did not provide Transmission Owners or Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.~~A Transmission Operator or

				Reliability Coordinator failed to use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board ~~of Trustees~~	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board ~~of Trustees~~: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3		Project 2015-09 Adopt revised standard.	Revision

Standard Development Timeline

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

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements

2. **Number:** PRC-002-32

3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.

4. **Applicability:**

Functional Entities:

4.1 Reliability Coordinator~~The Responsible Entity is:~~

~~Eastern Interconnection – Planning Coordinator~~

~~**4.1.1 4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator**~~

~~**4.1.3** Western Interconnection – Reliability Coordinator~~

~~**4.1.4** Quebec Interconnection – Planning Coordinator or Reliability Coordinator~~

4.2 Transmission Owner

4.3 Generator Owner

5. **Effective Dates:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-2, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have

dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator~~Responsible Entity~~ shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Reliability Coordinator's~~Responsible Entity's~~ historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Reliability Coordinator~~Responsible Entity~~ has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator~~Responsible Entity~~ has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for

common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
○ Eastern Interconnection	<59.75 Hz	>61.0 Hz
○ Western Interconnection	<59.55 Hz	>61.0 Hz
○ ERCOT Interconnection	<59.35 Hz	>61.0 Hz
○ Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

○ Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
○ Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
○ ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
○ Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator~~Responsible Entity~~, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting

entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

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 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 Transmission Owner, Generator Owner, ~~Planning Coordinator,~~ and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The ~~Responsible Entity (Planning Coordinator or~~ Reliability Coordinator~~, as applicable)~~ shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator ~~Responsible Entity~~ is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the	The ~~Responsible Entity~~ Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the

			required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.

R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data,

			in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as determined in Requirement R5.	in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.

R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority.

			by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12

			reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal to 100-calendar days after discovery of the failure.	reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal to 110-calendar days after discovery of the failure.	reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	~~RE (PC |~~ RC~~)~~	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

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 Functional Entities:

~~When the term "Responsible Entity" is used in PRC-002-2, it specifically refers to those entities listed under 4.1. The Responsible Entity – the Planning Coordinator or~~Because the Reliability Coordinator~~, as applicable in each Interconnection –~~ has the best wide-area view of the BES, the Reliability Coordinator ~~and~~ is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:
The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:
The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:
Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:
DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator~~Responsible Entity~~ has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the ~~Responsible Entity~~Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

~~The Responsible Entity, for the purposes of this standard, is defined as the PC or RC depending upon Interconnection, because they have the best overall perspective for determining wide-area DDR coverage. The Planning Coordinator and Reliability Coordinator assume different functions across the continent; therefore the Responsible Entity is defined in the Applicability Section and used throughout this standard.~~

The ~~Responsible Entity~~Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The ~~Responsible Entity~~Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the ~~Responsible Entity~~Reliability Coordinator. Data for each BES Element as defined by the ~~Responsible Entity~~Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two ~~Responsible Entities~~Reliability Coordinators, each ~~Responsible Entity~~Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the ~~Responsible Entity~~Reliability Coordinator will determine which entity will provide the data. The ~~Responsible Entity~~Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all ~~Responsible Entities~~Reliability Coordinators. It is intended that each ~~Responsible Entity~~Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:
DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:
A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.
Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:
An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.
An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:
Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).
Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:
Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:
Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-2 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-2 addresses "what" data is recorded, not "how" it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_r$, is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the ~~Responsible Entity's~~Reliability Coordinator ~~a~~Area, DDR data capability is required. If a ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed

the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the

potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the ~~Responsible Entity~~Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term

and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10: Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the ~~Responsible Entity~~Reliability Coordinator, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files

did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a "reasonable" amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Standard Development Timeline

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

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** **Transmission Relay Loadability**

2. **Number:** PRC-023-54

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. **Applicability:**

   4.1. Functional Entity:

   4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

   4.1.4 Planning Coordinator

   4.2. Circuits:

   4.2.1 Circuits Subject to Requirements R1 – R5:

   4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

   4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.2 Circuits Subject to Requirement R6:

   4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used

exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. Effective Dates: See Implementation Plan for the Revised Definition of "Remedial Action Scheme".

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).

3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

- An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
- An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

6. Not used.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

---

[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-4 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-4, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is

set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

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

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		the list was established or updated. (part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

Version	Date	Action	Change Tracking
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	

PRC-023-4 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

1.1. Phase distance.

1.2. Out-of-step tripping.

1.3. Switch-on-to-fault.

1.4. Overcurrent relays.

1.5. Communications aided protection schemes including but not limited to:

1.5.1 Permissive overreach transfer trip (POTT).

1.5.2 Permissive under-reach transfer trip (PUTT).

1.5.3 Directional comparison blocking (DCB).

1.5.4 Directional comparison unblocking (DCUB).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Not used.

2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-4 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator based on Planning Assessments that identify instances of instability, Cascading, or uncontrolled separation.

~~**B2.** The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.~~

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

   i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

   ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

   iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

Standard Development Timeline

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

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with initial ballot	June 2018 – July 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** **Relay Performance During Stable Power Swings**

2. **Number:** **PRC-026-2~~1~~**

3. **Purpose:** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Generator Owner that applies load-responsive protective relays as described in PRC-026-1 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.1.2 Planning Coordinator.

   4.1.3 Transmission Owner that applies load-responsive protective relays as described in PRC-026-1 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.2. Facilities: The following Elements that are part of the Bulk Electric System (BES):

   4.2.1 Generators.

   4.2.2 Transformers.

   4.2.3 Transmission lines.

5. **Background:**

   This is the third phase of a three-phased standard development project that focused on developing this new Reliability Standard to address protective relay operations due to stable power swings. The March 18, 2010, Federal Energy Regulatory Commission (FERC) Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In that Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, development of a new Reliability Standard to address generator protective relay loadability, and a new Reliability Standard to address the operation of protective relays due to stable power swings. This project's SAR addresses these directives with a three-phased approach to standard development.

   Phase 1 focused on making the specific modifications from FERC Order No. 733 to PRC-023-1. Reliability Standard PRC-023-2, which incorporated these modifications, became mandatory on July 1, 2012.

   Phase 2 focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. PRC-025-1 became mandatory on October 1, 2014, along with PRC-023-3, which was modified to harmonize PRC-023-2 with PRC-025-1.

   Phase 3 focuses on preventing protective relays from tripping unnecessarily due to stable power swings by requiring identification of Elements on which a stable or unstable power

swing may affect Protection System operation, assessment of the security of load-responsive protective relays to tripping in response to only a stable power swing, and implementation of Corrective Action Plans (CAP), where necessary. Phase 3 improves security of load-responsive protective relays for stable power swings so they are expected to not trip in response to stable power swings during non-Fault conditions while maintaining dependable fault detection and dependable out-of-step tripping.

6. Effective Dates:

Requirement R1

First day of the first full calendar year that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirements R2, R3, and R4

First day of the first full calendar year that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year 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.

B. Requirements and Measures

R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Criteria:

1. Generator(s) where an angular stability constraint exists that is addressed by a limiting the output of a generatorSystem Operating Limit (SOL) or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).
2. An Elements associated with that is monitored as part of an SOL identified by the Planning Coordinator's methodology[1] based on an angular instability identified in Planning Assessmentsconstraint.
3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.
4. An Element identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[2] power swing during a simulated disturbance.

M1. Each Planning Coordinator shall have dated evidence that demonstrates notification of the generator, transformer, and transmission line BES Element(s) that meet one or more of the criteria in Requirement R1, if any, to the respective Generator Owner and Transmission Owner. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

[1] NERC Reliability Standard FAC-014-2 – Establish and Communicate System Operating Limits, Requirement R3.

[2] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

R2. Each Generator Owner and Transmission Owner shall: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

2.1 Within 12 full calendar months of notification of a BES Element pursuant to Requirement R1, determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1 – Attachment B where an evaluation of that Element's load-responsive protective relay(s) based on PRC-026-1 – Attachment B criteria has not been performed in the last five calendar years.

2.2 Within 12 full calendar months of becoming aware[3] of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable[4] power swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1 – Attachment B.

M2. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates the evaluation was performed according to Requirement R2. Evidence may include, but is not limited to, the following documentation: apparent impedance characteristic plots, email, design drawings, facsimiles, R-X plots, software output, records, reports, transmittals, lists, settings sheets, or spreadsheets.

R3. Each Generator Owner and Transmission Owner shall, within six full calendar months of determining a load-responsive protective relay does not meet the PRC-026-1 – Attachment B criteria pursuant to Requirement R2, develop a Corrective Action Plan (CAP) to meet one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- The Protection System meets the PRC-026-1 – Attachment B criteria, while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element); or
- The Protection System is excluded under the PRC-026-1 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element).

M3. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates the development of a CAP in accordance with Requirement R3. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

R4. Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R3 and update each CAP if actions or timetables change until all actions are complete. *[Violation Risk Factor: Medium][Time Horizon: Long-Term Planning]*

M4. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates implementation of each CAP according to Requirement R4, including updates to the CAP when actions or timetables change. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

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 Generator Owner, Planning Coordinator, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator shall retain evidence of Requirement R1 for a minimum of one calendar year following the completion of the Requirement.
- The Generator Owner and Transmission Owner shall retain evidence of Requirement R2 evaluation for a minimum of 12 calendar months following completion of each evaluation where a CAP is not developed.
- The Generator Owner and Transmission Owner shall retain evidence of Requirements R2, R3, and R4 for a minimum of 12 calendar months following completion of each CAP.

If a Generator Owner, Planning Coordinator, or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

---

[3] Some examples of the ways an entity may become aware of a power swing are provided in the Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing."

[4] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure; "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was less than or equal to 30 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 90 calendar days late. OR The Planning Coordinator failed to provide notification of the BES Element(s) in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	High	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was less than or equal to 30 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 90 calendar days late. OR The Generator Owner or Transmission Owner failed to evaluate its load-responsive protective relay(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Long-term Planning	Medium	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than six calendar months and less than or equal to seven calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than seven calendar months and less than or equal to eight calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than eight calendar months and less than or equal to nine calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than nine calendar months. OR The Generator Owner or Transmission Owner failed to develop a CAP in accordance with Requirement R3.
R4	Long-term Planning	Medium	The Generator Owner or Transmission Owner implemented a Corrective Action Plan (CAP), but failed to update a CAP when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The Generator Owner or Transmission Owner failed to implement a Corrective Action Plan (CAP) in accordance with Requirement R4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Applied Protective Relaying, Westinghouse Electric Corporation, 1979.

Burdy, John, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

IEEE Power System Relaying Committee WG D6, *Power Swing and Out-of-Step Considerations on Transmission Lines*, July 2005: http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Kimbark Edward Wilson, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

Kundur, Prabha, *Power System Stability and Control*, 1994, Palo Alto: EPRI, McGraw Hill, Inc.

NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf.

Reimert, Donald, *Protective Relaying for Power Generation Systems*, 2006, Boca Raton: CRC Press.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by NERC Board of Trustees	New
1	March 17, 2016	FERC Order issued approving PRC-026-1. Docket No. RM15-8-000.	

PRC-026-1 – Attachment A

This standard applies to any protective functions which could trip instantaneously or with a time delay of less than 15 cycles on load current (i.e., "load-responsive") including, but not limited to:

- Phase distance
- Phase overcurrent
- Out-of-step tripping
- Loss-of-field

The following protection functions are excluded from Requirements of this standard:

- Relay elements supervised by power swing blocking
- Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Relay elements that are only enabled during a loss of communications
- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
- Relay elements associated with direct current (dc) lines
- Relay elements associated with dc converter transformers
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (i.e., in order to prevent false operation in the event of a loss of potential)
- Relay elements associated with switch-onto-fault schemes
- Reverse power relay on the generator
- Generator relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes)
- Current differential relay, pilot wire relay, and phase comparison relay
- Voltage-restrained or voltage-controlled overcurrent relays

PRC-026-1 – Attachment B

Criterion A:

An impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region.[5] The unstable power swing region is formed by the union of three shapes in the impedance (R-X) plane; (1) a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7; (2) an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43; (3) a lens that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending-end and receiving-end voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.

[5] Guidelines and Technical Basis, Figures 1 and 2.

PRC-026-1 – Attachment B

Criterion B:

The pickup of an overcurrent relay element used for tripping, that is above the calculated current value (with the parallel transfer impedance removed) for the conditions below:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.
4. Both the sending-end and receiving-end voltages at 1.05 per unit.

Guidelines and Technical Basis

Introduction

The NERC System Protection and Control Subcommittee technical document, *Protection System Response to Power Swings*, August 2013,[6] ("PSRPS Report" or "report") was specifically prepared to support the development of this NERC Reliability Standard. The report provided a historical perspective on power swings as early as 1965 up through the approval of the report by the NERC Planning Committee. The report also addresses reliability issues regarding trade-offs between security and dependability of Protection Systems, considerations for this NERC Reliability Standard, and a collection of technical information about power swing characteristics and varying issues with practical applications and approaches to power swings. Of these topics, the report suggests an approach for this NERC Reliability Standard ("standard" or "PRC-026-1") which is consistent with addressing three regulatory directives in the FERC Order No. 733. The first directive concerns the need for "…protective relay systems that differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement."[7] Second, is "…to develop a Reliability Standard addressing undesirable relay operation due to stable power swings."[8] The third directive "…to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings"[9] was considered during development of the standard.

The development of this standard implements the majority of the approaches suggested by the report. However, it is noted that the Reliability Coordinator and Transmission Planner have not been included in the standard's Applicability section (as suggested by the PSRPS Report). This is so that a single entity, the Planning Coordinator, may be the single source for identifying Elements according to Requirement R1. A single source will insure that multiple entities will not identify Elements in duplicate, nor will one entity fail to provide an Element because it believes the Element is being provided by another entity. The Planning Coordinator has, or has access to, the wide-area model and can correctly identify the Elements that may be susceptible to a stable or unstable power swing. Additionally, not including the Reliability Coordinator and Transmission Planner is consistent with the applicability of other relay loadability NERC Reliability Standards (e.g., PRC-023 and PRC-025). It is also consistent with the NERC Functional Model.

The phrase, "while maintaining dependable fault detection and dependable out-of-step tripping" in Requirement R3, describes that the Generator Owner and Transmission Owner are to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the transmission system, and

---

[6] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

[7] Transmission Relay Loadability Reliability Standard, Order No. 733, P.150 FERC ¶ 61,221 (2010).

[8] Ibid. P.153.

[9] Ibid. P.162.

this standard is not intended to result in the loss of these protection functions. Instead, the Generator Owner and Transmission Owner must consider both the Requirements within this standard and its desired protection goals and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

Power Swings

The IEEE Power System Relaying Committee WG D6 developed a technical document called *Power Swing and Out-of-Step Considerations on Transmission Lines* (July 2005) that provides background on power swings. The following are general definitions from that document:[10]

> Power Swing: a variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.
>
> Pole Slip: a condition whereby a generator, or group of generators, terminal voltage angles (or phases) go past 180 degrees with respect to the rest of the connected power system.
>
> Stable Power Swing: a power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.
>
> Unstable Power Swing: a power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.
>
> Out-of-Step Condition: Same as an unstable power swing.
>
> Electrical System Center or Voltage Zero: it is the point or points in the system where the voltage becomes zero during an unstable power swing.

Burden to Entities

The PSRPS Report provides a technical basis and approach for focusing on Protection Systems, which are susceptible to power swings, while achieving the purpose of the standard. The approach reduces the number of relays to which the PRC-026-1 Requirements would apply by first identifying the BES Element(s) on which load-responsive protective relays must be evaluated. The first step uses criteria to identify the Elements on which a Protection System is expected to be challenged by power swings. Of those Elements, the second step is to evaluate each load-responsive protective relay that is applied on each identified Element. Rather than requiring the Planning Coordinator or Transmission Planner to perform simulations to obtain information for each identified Element, the Generator Owner and Transmission Owner will reduce the need for simulation by comparing the load-responsive protective relay characteristic to specific criteria in PRC-026-1 – Attachment B.

[10] http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Applicability

The standard is applicable to the Generator Owner, Planning Coordinator, and Transmission Owner entities. More specifically, the Generator Owner and Transmission Owner entities are applicable when applying load-responsive protective relays at the terminals of the applicable BES Elements. The standard is applicable to the following BES Elements: generators, transformers, and transmission lines. The Distribution Provider was considered for inclusion in the standard; however, it is not subject to the standard because this entity, by functional registration, would not own generators, transmission lines, or transformers other than load serving.

Load-responsive protective relays include any protective functions which could trip with or without time delay, on load current.

Requirement R1

The Planning Coordinator has a wide-area view and is in the position to identify what, if any, Elements meet the criteria. The criterion-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document, *Protection System Response to Power Swings (*August 2013),[11] which recommends a focused approach to determine an at-risk Element. Identification of Elements comes from the annual Planning Assessments pursuant to the transmission planning (i.e., "TPL") and other NERC Reliability Standards (e.g., PRC-006), and the standard is not requiring any other assessments to be performed by the Planning Coordinator. The required notification on a calendar year basis to the respective Generator Owner and Transmission Owner is sufficient because it is expected that the Planning Coordinator will make its notifications following the completion of its annual Planning Assessments. The Planning Coordinator will continue to provide notification of Elements on a calendar year basis even if a study is performed less frequently (e.g., PRC-006 – Automatic Underfrequency Load Shedding, which is five years) and has not changed. It is possible that a Planning Coordinator could utilize studies from a prior year in determining the necessary notifications pursuant to Requirement R1.

Criterion 1

The first criterion involves generator(s) where an angular stability constraint exists that is addressed by limiting the output of a generator~~a System Operating Limit (SOL)~~ or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). For example, a scheme to remove generation for specific conditions is implemented for a four-unit generating plant (1,100 MW). Two of the units are 500 MW each; one is connected to the 345 kV system and one is connected to the 230 kV system. The Transmission Owner has two 230 kV transmission lines and one 345 kV transmission line all terminating at the generating facility as well as a 345/230 kV autotransformer. The remaining 100 MW consists of two 50 MW combustion turbine (CT) units connected to four 66 kV transmission lines. The 66 kV transmission lines are not electrically joined to the 345 kV and 230 kV transmission lines at the plant site and are not subject to ~~the operating limit~~ any generating output limitation or RAS. A

[11] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

stability constraint limits the output of the portion of the plant affected by the RAS to 700 MW for an outage of the 345 kV transmission line. The RAS trips one of the 500 MW units to maintain stability for a loss of the 345 kV transmission line when the total output from both 500 MW units is above 700 MW. For this example, both 500 MW generating units and the associated generator step-up (GSU) transformers would be identified as Elements meeting this criterion. The 345/230 kV autotransformer, the 345 kV transmission line, and the two 230 kV transmission lines would also be identified as Elements meeting this criterion. The 50 MW combustion turbines and 66 kV transmission lines would not be identified pursuant to Criterion 1 because these Elements are not subject to ~~an operating limit~~ any generating output limitation or RAS and do not terminate at the Transmission station associated with the generators that are subject to any generating output limitation~~the SOL~~ or RAS.

Criterion 2

The second criterion involves Elements associated with angular instability identified in the Planning Assessments~~that are monitored as a part of an established System Operating Limit (SOL) based on an angular stability limit regardless of the outage conditions that result in the enforcement of the SOL~~. For example, if Planning Assessments have identified that an angular instability could limit transfer capability on two long parallel 500 kV transmission lines ~~have a combined SOL of~~ to a maximum of 1,200 MW, and this limitation is based on angular instability resulting from a fault and subsequent loss of one of the two lines, then both lines would be identified as Elements meeting the criterion.

Criterion 3

The third criterion involves Elements that form the boundary of an island within an underfrequency load shedding (UFLS) design assessment. The criterion applies to islands identified based on application of the Planning Coordinator's criteria for identifying islands, where the island is formed by tripping the Elements based on angular instability. The criterion applies if the angular instability is modeled in the UFLS design assessment, or if the boundary is identified "off-line" (i.e., the Elements are selected based on angular instability considerations, but the Elements are tripped in the UFLS design assessment without modeling the initiating angular instability). In cases where an out-of-step condition is detected and tripping is initiated at an alternate location, the criterion applies to the Element on which the power swing is detected. The criterion does not apply to islands identified based on other considerations that do not involve angular instability, such as excessive loading, Planning Coordinator area boundary tie lines, or Balancing Authority boundary tie lines.

Criterion 4

The fourth criterion involves Elements identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[12] power swing during a simulated

[12] Refer to the "Justification for Including Unstable Power Swings in the Requirements" section.

disturbance. The intent is for the Planning Coordinator to include any Element(s) where relay tripping was observed during simulations performed for the most recent annual Planning Assessment associated with the transmission planning TPL-001-4 Reliability Standard. Note that relay tripping must be assessed within those annual Planning Assessments per TPL-001-4, R4, Part 4.3.1.3, which indicates that analysis shall include the "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models." Identifying such Elements according to Criterion 4 and notifying the respective Generator Owner and Transmission Owner will require that the owners of any load-responsive protective relay applied at the terminals of the identified Element evaluate the relay's susceptibility to tripping in response to a stable power swing.

Planning Coordinators have the discretion to determine whether the observed tripping for a power swing in its Planning Assessments occurs for valid contingencies and system conditions. The Planning Coordinator will address tripping that is observed in transient analyses on an individual basis; therefore, the Planning Coordinator is responsible for identifying the Elements based only on simulation results that are determined to be valid.

Due to the nature of how a Planning Assessment is performed, there may be cases where a previously-identified Element is not identified in the most recent annual Planning Assessment. If so, this is acceptable because the Generator Owner and Transmission Owner would have taken action upon the initial notification of the previously identified Element. When an Element is not identified in later Planning Assessments, the risk of load-responsive protective relays tripping in response to a stable power swing during non-Fault conditions would have already been assessed under Requirement R2 and mitigated according to Requirements R3 and R4 where the relays did not meet the PRC-026-1 – Attachment B criteria. According to Requirement R2, the Generator Owner and Transmission Owner are only required to re-evaluate each load-responsive protective relay for an identified Element where the evaluation has not been performed in the last five calendar years.

Although Requirement R1 requires the Planning Coordinator to notify the respective Generator Owner and Transmission Owner of any Elements meeting one or more of the four criteria, it does not preclude the Planning Coordinator from providing additional information, such as apparent impedance characteristics, in advance or upon request, that may be useful in evaluating protective relays. Generator Owners and Transmission Owners are able to complete protective relay evaluations and perform the required actions without additional information. The standard does not include any requirement for the entities to provide information that is already being shared or exchanged between entities for operating needs. While a Requirement has not been included for the exchange of information, entities should recognize that relay performance needs to be measured against the most current information.

Requirement R2

Requirement R2 requires the Generator Owner and Transmission Owner to evaluate its load-responsive protective relays to ensure that they are expected to not trip in response to stable power swings.

The PRC-026-1 – Attachment A lists the applicable load-responsive relays that must be evaluated which include phase distance, phase overcurrent, out-of-step tripping, and loss-of-field relay functions. Phase distance relays could include, but are not limited to, the following:

- Zone elements with instantaneous tripping or intentional time delays of less than 15 cycles
- Phase distance elements used in high-speed communication-aided tripping schemes including:
  - Directional Comparison Blocking (DCB) schemes
  - Directional Comparison Un-Blocking (DCUB) schemes
  - Permissive Overreach Transfer Trip (POTT) schemes
  - Permissive Underreach Transfer Trip (PUTT) schemes

A method is provided within the standard to support consistent evaluation by Generator Owners and Transmission Owners based on specified conditions. Once a Generator Owner or Transmission Owner is notified of Elements pursuant to Requirement R1, it has 12 full calendar months to determine if each Element's load-responsive protective relays meet the PRC-026-1 – Attachment B criteria, if the determination has not been performed in the last five calendar years. Additionally, each Generator Owner and Transmission Owner, that becomes aware of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relays pursuant to Requirement R2, Part 2.2, must perform the same PRC-026-1 – Attachment B criteria determination within 12 full calendar months.

Becoming Aware of an Element That Tripped in Response to a Power Swing

Part 2.2 in Requirement R2 is intended to initiate action by the Generator Owner and Transmission Owner when there is a known stable or unstable power swing and it resulted in the entity's Element tripping. The criterion starts with becoming aware of the event (i.e., power swing) and then any connection with the entity's Element tripping. By doing so, the focus is removed from the entity having to demonstrate that it made a determination whether a power swing was present for every Element trip. The basis for structuring the criterion in this manner is driven by the available ways that a Generator Owner and Transmission Owner could become aware of an Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s).

Element trips caused by stable or unstable power swings, though infrequent, would be more common in a larger event. The identification of power swings will be revealed during an analysis of the event. Event analysis where an entity may become aware of a stable or unstable power swing could include internal analysis conducted by the entity, the entity's Protection System review following a trip, or a larger scale analysis by other entities. Event analysis could include involvement by the entity's Regional Entity, and in some cases NERC.

Information Common to Both Generation and Transmission Elements

The PRC-026-1 – Attachment A lists the load-responsive protective relays that are subject to this standard. Generator Owners and Transmission Owners may own load-responsive protective relays (e.g., distance relays) that directly affect generation or transmission BES Elements and will require analysis as a result of Elements being identified by the Planning Coordinator in Requirement R1

or the Generator Owner or Transmission Owner in Requirement R2. For example, distance relays owned by the Transmission Owner may be installed at the high-voltage side of the generator step-up (GSU) transformer (directional toward the generator) providing backup to generation protection. Generator Owners may have distance relays applied to backup transmission protection or backup protection to the GSU transformer. The Generator Owner may have relays installed at the generator terminals or the high-voltage side of the GSU transformer.

Exclusion of Time Based Load-Responsive Protective Relays

The purpose of the standard is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions." Load-responsive, high-speed tripping protective relays pose the highest risk of operating during a power swing. Because of this, high-speed tripping protective relays and relays with a time delay of less than 15 cycles are included in the standard; whereas other relays (i.e., Zones 2 and 3) with a time delay of 15 cycles or greater are excluded. The time delay used for exclusion on some load-responsive protective relays is based on the maximum expected time that load-responsive protective relays would be exposed to a stable power swing with a slow slip rate frequency.

In order to establish a time delay that distinguishes a high-risk load-responsive protective relay from one that has a time delay for tripping (lower-risk), a sample of swing rates were calculated based on a stable power swing entering and leaving the impedance characteristic as shown in Table 1. For a relay impedance characteristic that has a power swing entering and leaving, beginning at 90 degrees with a termination at 120 degrees before exiting the zone, the zone timer must be greater than the calculated time the stable power swing is inside the relay's operating zone to not trip in response to the stable power swing.

Eq. (1) $$Zone\ timer > 2 \times \left(\frac{(120° - Angle\ of\ entry\ into\ the\ relay\ characteristic) \times 60}{(360 \times Slip\ Rate)}\right)$$

Table 1: Swing Rates

Zone Timer (Cycles)	Slip Rate (Hz)
10	1.00
15	0.67
20	0.50
30	0.33

With a minimum zone timer of 15 cycles, the corresponding slip rate of the system is 0.67 Hz. This represents an approximation of a slow slip rate during a system Disturbance. Longer time delays allow for slower slip rates.

Application to Transmission Elements

Criterion A in PRC-026-1 – Attachment B describes an unstable power swing region that is formed by the union of three shapes in the impedance (R-X) plane. The first shape is a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7 (i.e., E_S / E_R = 0.7 / 1.0 = 0.7). The second shape is an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43 (i.e., E_S / E_R = 1.0 / 0.7 = 1.43). The third shape is a lens that connects the endpoints of the total system impedance together by varying the sending-end and receiving-end system voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance (with the parallel transfer impedance removed—see Figures 1 through 5). The total system impedance is derived from a two-bus equivalent network and is determined by summing the sending-end source impedance, the line impedance (excluding the Thévenin equivalent transfer impedance), and the receiving-end source impedance as shown in Figures 6 and 7. Establishing the total system impedance provides a conservative condition that will maximize the security of the relay against various system conditions. The smallest total system impedance represents a condition where the size of the lens characteristic in the R-X plane is smallest and is a conservative operating point from the standpoint of ensuring a load-responsive protective relay is expected to not trip given a predetermined angular displacement between the sending-end and receiving-end voltages. The smallest total system impedance results when all generation is in service and all transmission BES Elements are modeled in their "normal" system configuration (PRC-026-1 – Attachment B, Criterion A). The parallel transfer impedance is removed to represent a likely condition where parallel Elements may be lost during the disturbance, and the loss of these Elements magnifies the sensitivity of the load-responsive relays on the parallel line by removing the "infeed effect" (i.e., the apparent impedance sensed by the relay is decreased as a result of the loss of the transfer impedance, thus making the relay more likely to trip for a stable power swing—See Figures 13 and 14).

The sending-end and receiving-end source voltages are varied from 0.7 to 1.0 per unit to form the lower and upper loss-of-synchronism circles. The ratio of these two voltages is used in the calculation of the loss-of-synchronism circles, and result in a ratio range from 0.7 to 1.43.

Eq. (2) $$\frac{E_S}{E_R} = \frac{0.7}{1.0} = 0.7$$

Eq. (3): $$\frac{E_S}{E_R} = \frac{1.0}{0.7} = 1.43$$

The internal generator voltage during severe power swings or transmission system fault conditions will be greater than zero due to voltage regulator support. The voltage ratio of 0.7 to 1.43 is chosen to be more conservative than the PRC-023[13] and PRC-025[14] NERC Reliability Standards where a lower bound voltage of 0.85 per unit voltage is used. A ±15% internal generator voltage range was chosen as a conservative voltage range for calculation of the voltage ratio used to calculate the loss-of-synchronism circles. For example, the voltage ratio using these voltages would result in a ratio range from 0.739 to 1.353.

[13] Transmission Relay Loadability

[14] Generator Relay Loadability

Eq. (4) $$\frac{E_S}{E_R} = \frac{0.85}{1.15} = 0.739$$ Eq. (5): $$\frac{E_S}{E_R} = \frac{1.15}{0.85} = 1.353$$

The lower ratio is rounded down to 0.7 to be more conservative, allowing a voltage range of 0.7 to 1.0 per unit to be used for the calculation of the loss-of-synchronism circles.[15]

When the parallel transfer impedance is included in the model, the division of current through the parallel transfer impedance path results in actual measured relay impedances that are larger than those measured when the parallel transfer impedance is removed (i.e., infeed effect), which would make it more likely for an impedance relay element to be completely contained within the unstable power swing region as shown in Figure 11. If the transfer impedance is included in the evaluation, a distance relay element could be deemed as meeting PRC-026-1 – Attachment B criteria and, in fact would be secure, assuming all Elements were in their normal state. In this case, the distance relay element could trip in response to a stable power swing during an actual event if the system was weakened (i.e., a higher transfer impedance) by the loss of a subset of lines that make up the parallel transfer impedance as shown in Figure 10. This could happen because the subset of lines that make up the parallel transfer impedance tripped on unstable swings, contained the initiating fault, and/or were lost due to operation of breaker failure or remote back-up protection schemes.

Table 10 shows the percent size increase of the lens shape as seen by the relay under evaluation when the parallel transfer impedance is included. The parallel transfer impedance has minimal effect on the apparent size of the lens shape as long as the parallel transfer impedance is at least 10 multiples of the parallel line impedance (less than 5% lens shape expansion), therefore, its removal has minimal impact, but results in a slightly more conservative, smaller lens shape. Parallel transfer impedances of 5 multiples of the parallel line impedance or less result in an apparent lens shape size of 10% or greater as seen by the relay. If two parallel lines and a parallel transfer impedance tie the sending-end and receiving-end buses together, the total parallel transfer impedance will be one or less multiples of the parallel line impedance, resulting in an apparent lens shape size of 45% or greater. It is a realistic contingency that the parallel line could be out-of-service, leaving the parallel transfer impedance making up the rest of the system in parallel with the line impedance. Since it is not known exactly which lines making up the parallel transfer impedance will be out of service during a major system disturbance, it is most conservative to assume that all of them are out, leaving just the line under evaluation in service.

Either the saturated transient or sub-transient direct axis reactance may be used for machines in the evaluation because they are smaller than the un-saturated reactances. Since saturated sub-transient generator reactances are smaller than the transient or synchronous reactances, the use of sub-transient reactances will result in a smaller source impedance and a smaller unstable power swing region in the graphical analysis as shown in Figures 8 and 9. Because power swings occur in a time frame where generator transient reactances will be prevalent, it is acceptable to use saturated transient reactances instead of saturated sub-transient reactances. Because some short-

[15] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, Section 6 (The Cascade Stage of the Blackout), p. 94 under "Why the Generators Tripped Off," states, "Some generator undervoltage relays were set to trip at or above 90% voltage. However, a motor stalls out at about 70% voltage and a motor starter contactor drops out around 75%, so if there is a compelling need to protect the turbine from the system the under-voltage trigger point should be no higher than 80%."

circuit models may not include transient reactances, the use of sub-transient reactances is also acceptable because it produces more conservative results. For this reason, either value is acceptable when determining the system source impedances (PRC-026-1 – Attachment B, Criterion A and B, No. 3).

Saturated reactances are used in short-circuit programs that produce the system impedance mentioned above. Planning and stability software generally use un-saturated reactances. Generator models used in transient stability analyses recognize that the extent of the saturation effect depends upon both rotor (field) and stator currents. Accordingly, they derive the effective saturated parameters of the machine at each instant by internal calculation from the specified (constant) unsaturated values of machine reactances and the instantaneous internal flux level. The specific assumptions regarding which inductances are affected by saturation, and the relative effect of that saturation, are different for the various generator models used. Thus, unsaturated values of all machine reactances are used in setting up planning and stability software data, and the appropriate set of open-circuit magnetization curve data is provided for each machine.

Saturated reactance values are smaller than unsaturated reactance values and are used in short-circuit programs owned by the Generator and Transmission Owners. Because of this, saturated reactance values are to be used in the development of the system source impedances.

The source or system equivalent impedances can be obtained by a number of different methods using commercially available short-circuit calculation tools.[16] Most short-circuit tools have a network reduction feature that allows the user to select the local and remote terminal buses to retain. The first method reduces the system to one that contains two buses, an equivalent generator at each bus (representing the source impedances at the sending-end and receiving-end), and two parallel lines; one being the line impedance of the protected line with relays being analyzed, the other being the parallel transfer impedance representing all other combinations of lines that connect the two buses together as shown in Figure 6. Another conservative method is to open both ends of the line being evaluated, and apply a three-phase bolted fault at each bus to determine the Thévenin equivalent impedance at each bus. The source impedances are set equal to the Thévenin equivalent impedances and will be less than or equal to the actual source impedances calculated by the network reduction method. Either method can be used to develop the system source impedances at both ends.

The two bullets of PRC-026-1 – Attachment B, Criterion A, No. 1, identify the system separation angles used to identify the size of the power swing stability boundary for evaluating load-responsive protective relay impedance elements. The first bullet of PRC-026-1 – Attachment B, Criterion A, No. 1 evaluates a system separation angle of at least 120 degrees that is held constant while varying the sending-end and receiving-end source voltages from 0.7 to 1.0 per unit, thus creating an unstable power swing region about the total system impedance in Figure 1. This unstable power swing region is compared to the tripping portion of the distance relay characteristic; that is, the portion that is not supervised by load encroachment, blinders, or some other form of supervision as shown in Figure 12 that restricts the distance element from tripping

[16] Demetrios A. Tziouvaras and Daqing Hou, Appendix in *Out-Of-Step Protection Fundamentals and Advancements,* April 17, 2014: https://www.selinc.com.

for heavy, balanced load conditions. If the tripping portion of the impedance characteristics are completely contained within the unstable power swing region, the relay impedance element meets Criterion A in PRC-026-1 – Attachment B. A system separation angle of 120 degrees was chosen for the evaluation because it is generally accepted in the industry that recovery for a swing beyond this angle is unlikely to occur.[17]

The second bullet of PRC-026-1 – Attachment B, Criterion A, No. 1 evaluates impedance relay elements at a system separation angle of less than 120 degrees, similar to the first bullet described above. An angle less than 120 degrees may be used if a documented stability analysis demonstrates that the power swing becomes unstable at a system separation angle of less than 120 degrees.

The exclusion of relay elements supervised by Power Swing Blocking (PSB) in PRC-026-1 – Attachment A allows the Generator Owner or Transmission Owner to exclude protective relay elements if they are blocked from tripping by PSB relays. A PSB relay applied and set according to industry accepted practices prevent supervised load-responsive protective relays from tripping in response to power swings. Further, PSB relays are set to allow dependable tripping of supervised elements. The criteria in PRC-026-1 – Attachment B specifically applies to unsupervised elements that could trip for stable power swings. Therefore, load-responsive protective relay elements supervised by PSB can be excluded from the Requirements of this standard.

[17] "The critical angle for maintaining stability will vary depending on the contingency and the system condition at the time the contingency occurs; however, the likelihood of recovering from a swing that exceeds 120 degrees is marginal and 120 degrees is generally accepted as an appropriate basis for setting out-of-step protection. Given the importance of separating unstable systems, defining 120 degrees as the critical angle is appropriate to achieve a proper balance between dependable tripping for unstable power swings and secure operation for stable power swings." NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf), p. 28.

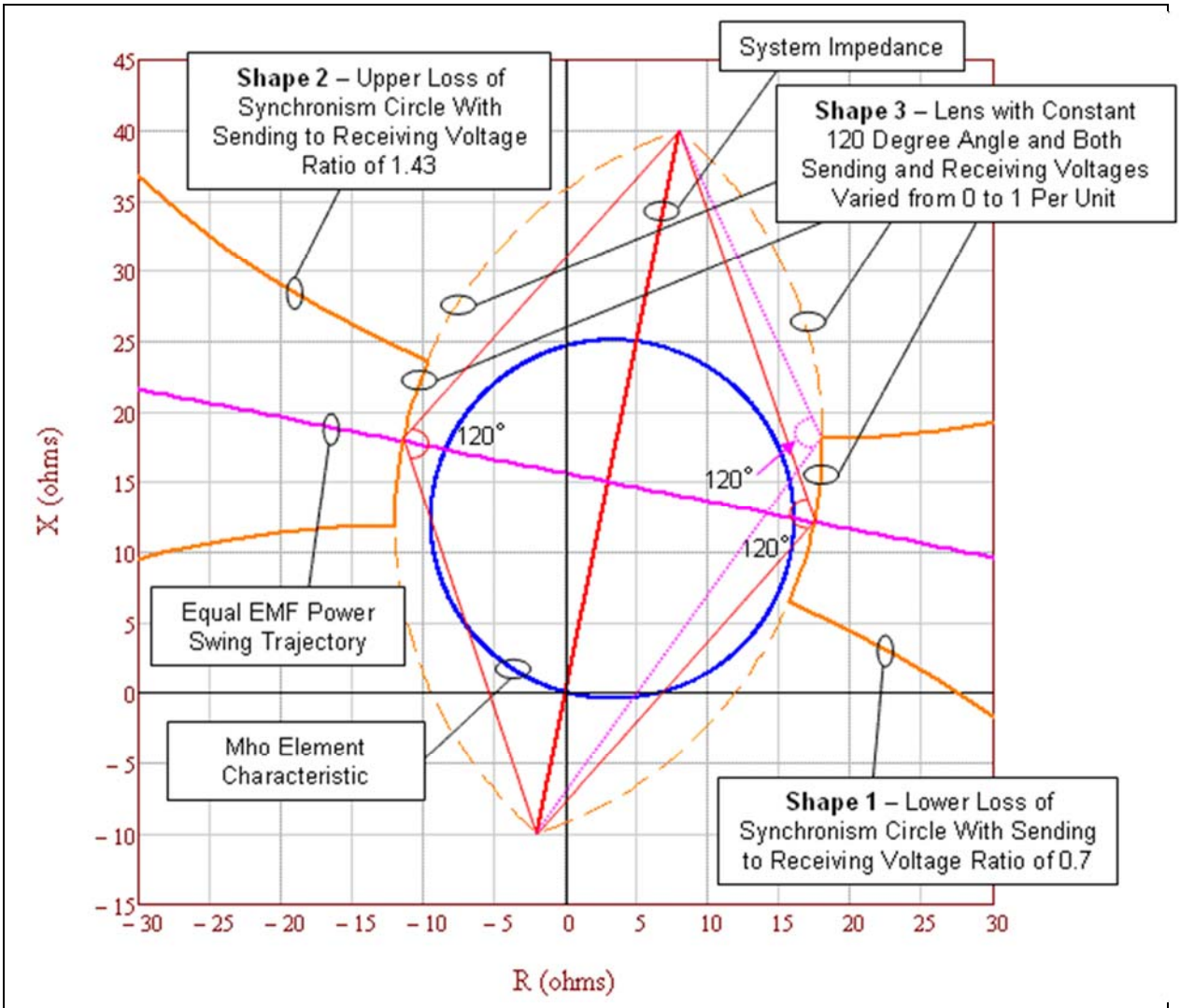


Figure 1: An enlarged graphic illustrating the unstable power swing region formed by the union of three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region (i.e., it does not intersect any portion of the unstable power swing region), therefore it meets PRC-026-1 – Attachment B, Criterion A, No. 1.

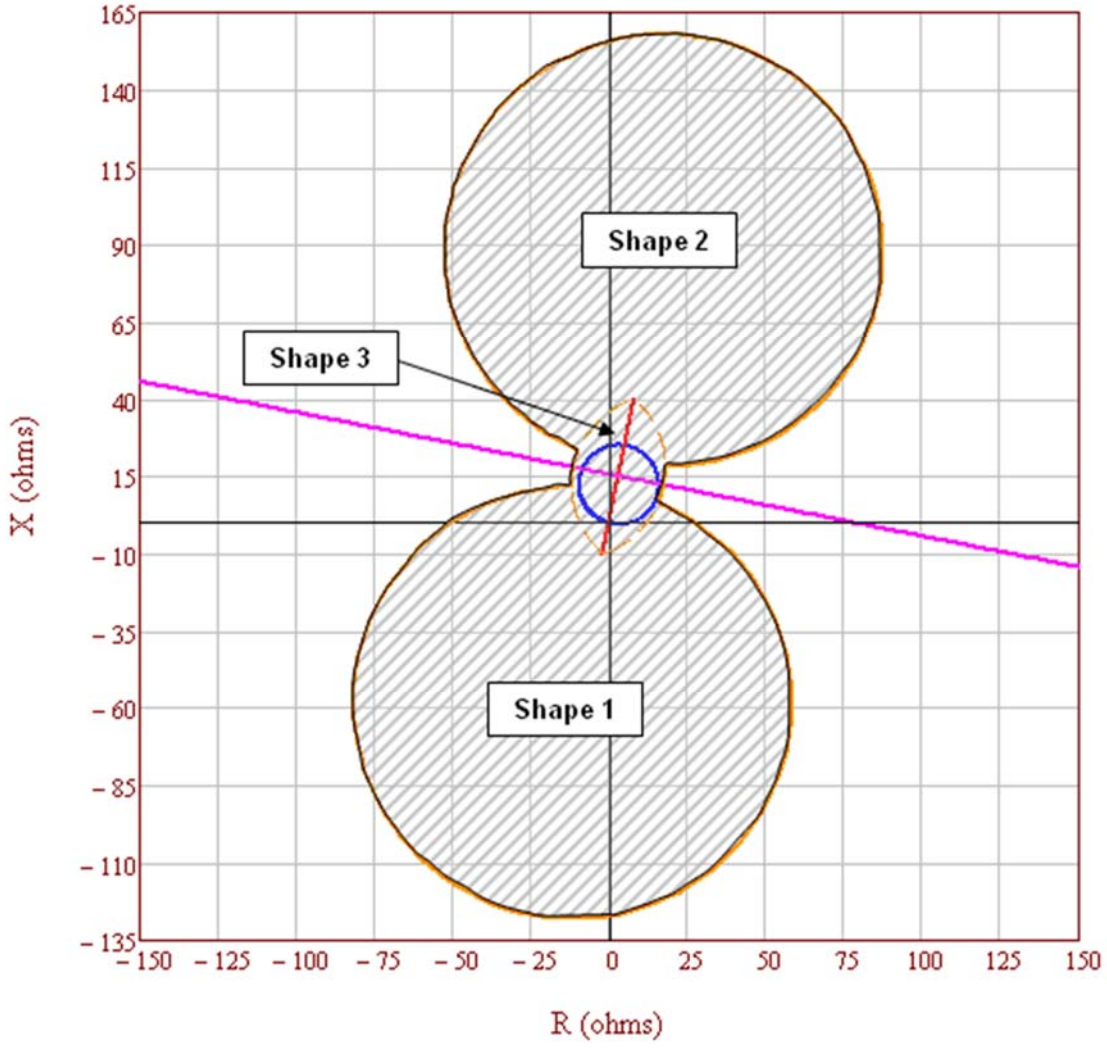


Figure 2: Full graphic of the unstable power swing region formed by the union of the three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region, therefore it meets PRC-26-1 – Attachment B, Criterion A, No.1.

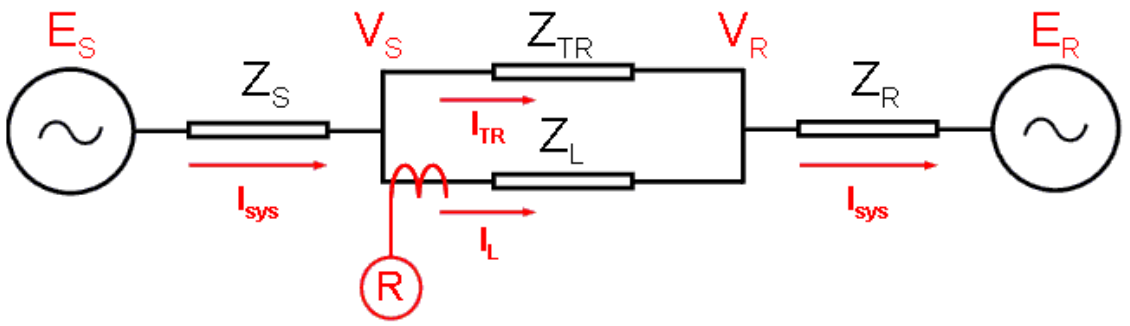


Figure 3: System impedances as seen by Relay R (voltage connections are not shown).

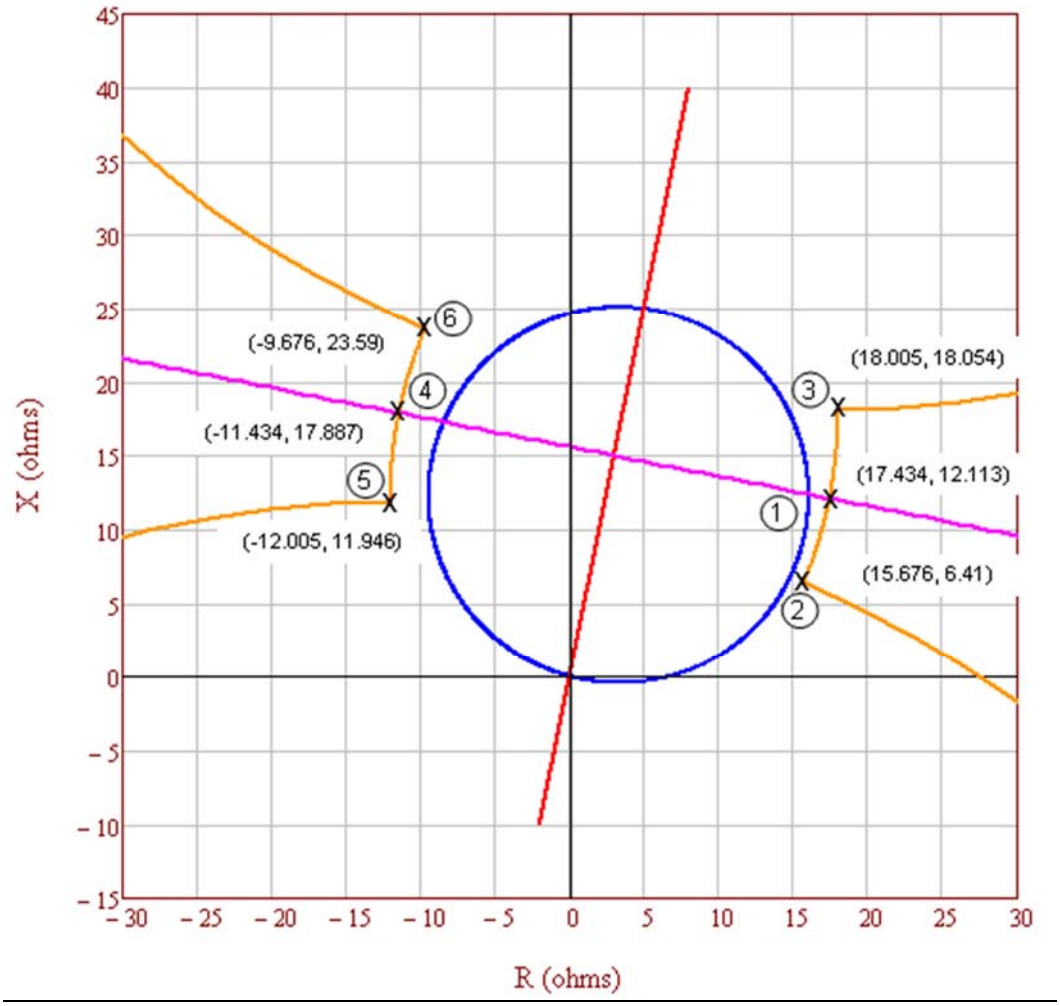


Figure 4: The defining unstable power swing region points where the lens shape intersects the lower and upper loss-of-synchronism circle shapes and where the lens intersects the equal EMF (electromotive force) power swing.

	Left Side Coordinates		Right Side Coordinates	
E_S / E_R Voltage Ratio	R	+ jX	R	+ jX
0.7	**-12.005**	**11.946**	**15.676**	**6.41**
0.72	-12.004	12.407	15.852	6.836
0.74	-11.996	12.857	16.018	7.255
0.76	-11.982	13.298	16.175	7.667
0.78	-11.961	13.729	16.321	8.073
0.8	-11.935	14.151	16.459	8.472
0.82	-11.903	14.563	16.589	8.865
0.84	-11.867	14.966	16.71	9.251
0.86	-11.826	15.361	16.824	9.631
0.88	-11.78	15.746	16.93	10.004
0.9	-11.731	16.123	17.03	10.371
0.92	-11.678	16.492	17.123	10.732
0.94	-11.621	16.852	17.209	11.086
0.96	-11.562	17.205	17.29	11.435
0.98	-11.499	17.55	17.364	11.777
1	**-11.434**	**17.887**	**17.434**	**12.113**
1.0286	-11.336	18.356	17.524	12.584
1.0572	-11.234	18.81	17.604	13.043
1.0858	-11.127	19.251	17.675	13.49
1.1144	-11.017	19.677	17.738	13.926
1.143	-10.904	20.091	17.792	14.351
1.1716	-10.788	20.491	17.84	14.766
1.2002	-10.67	20.88	17.88	15.17
1.2288	-10.55	21.256	17.914	15.564
1.2574	-10.428	21.621	17.942	15.948
1.286	-10.304	21.975	17.964	16.322
1.3146	-10.18	22.319	17.981	16.687
1.3432	-10.054	22.652	17.993	17.043
1.3718	-9.928	22.976	18.001	17.39
1.4004	-9.801	23.29	18.005	17.728
1.429	**-9.676**	**23.59**	**18.005**	**18.054**

Figure 5: Full table of 31 detailed lens shape point calculations. The bold highlighted rows correspond to the detailed calculations in Tables 2-7.

Table 2: Example Calculation (Lens Point 1)	
This example is for calculating the impedance the first point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 120 degrees. See Figures 3 and 4.	
Eq. (6)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$

Table 2: Example Calculation (Lens Point 1)			
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (7)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (8)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (9)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (10)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (11)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		

Table 2: Example Calculation (Lens Point 1)	
	$I_L = 4{,}511\angle 71.3° \; A \times \frac{(4 + j20) \times 10^{10} \; \Omega}{(4 + j20) \; \Omega + (4 + j20) \times 10^{10} \; \Omega}$
	$I_L = 4{,}511\angle 71.3° \; A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (12)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120° \; V - [(2 + j10) \; \Omega \times 4{,}511\angle 71.3° \; A]$
	$V_S = 95{,}757\angle 106.1° \; V$
The impedance seen by the relay on Z_L.	
Eq. (13)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1° \; V}{4{,}511\angle 71.3° \; A}$
	$Z_{L-Relay} = 17.434 + j12.113 \; \Omega$

Table 3: Example Calculation (Lens Point 2)			
This example is for calculating the impedance second point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (14)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 120° \; V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 120° \; V$		
Eq. (15)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0° \; V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0° \; V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10 \; \Omega$	$Z_L = 4 + j20 \; \Omega$	$Z_R = 4 + j20 \; \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10} \; \Omega$		

Table 3: Example Calculation (Lens Point 2)	
Total impedance between the generators.	
Eq. (16)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (17)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (18)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 77°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (19)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 77°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 77°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (20)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 92{,}953\angle 120°\ V - [(2 + j10\ )\Omega \times 3{,}854\angle 77°\ A]$
	$V_S = 65{,}271\angle 99°\ V$
The impedance seen by the relay on Z_L.	
Eq. (21)	$Z_{L-Relay} = \frac{V_S}{I_L}$

Table 3: Example Calculation (Lens Point 2)	
	$Z_{L-Relay} = \frac{65{,}271\angle 99°\ V}{3{,}854\angle 77°\ A}$
	$Z_{L-Relay} = 15.676 + j6.41\ \Omega$

Table 4: Example Calculation (Lens Point 3)			
This example is for calculating the impedance third point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (22)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (23)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (24)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (25)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		

Table 4: Example Calculation (Lens Point 3)	
Total system current from sending-end source.	
Eq. (26)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 92{,}953.7\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 65.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (27)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 65.5°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 65.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (28)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 3{,}854\angle 65.5°\ A]$
	$V_S = 98{,}265\angle 110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (29)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle 110.6°\ V}{3{,}854\angle 65.5°\ A}$
	$Z_{L-Relay} = 18.005 + j18.054\ \Omega$

Table 5: Example Calculation (Lens Point 4)	
This example is for calculating the impedance fourth point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 240 degrees. See Figures 3 and 4.	
Eq. (30)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$

Table 5: Example Calculation (Lens Point 4)			
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (31)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (32)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (33)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (34)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 240°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 131.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (35)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 131.1°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 131.1°\ A$		

Table 5: Example Calculation (Lens Point 4)			
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.			
Eq. (36)	$V_S = E_S - (Z_S \times I_L)$		
	$V_S = 132{,}791\angle 240° \, V - [(2 + j10\,)\,\Omega \times 4{,}511\angle 131.1° \, A]$		
	$V_S = 95{,}756\angle -106.1° \, V$		
The impedance seen by the relay on Z_L.			
Eq. (37)	$Z_{L-Relay} = \frac{V_S}{I_L}$		
	$Z_{L-Relay} = \frac{95{,}756\angle -106.1° \, V}{4{,}511\angle 131.1° \, A}$		
	$Z_{L-Relay} = -11.434 + j17.887\ \Omega$		

Table 6: Example Calculation (Lens Point 5)			
This example is for calculating the impedance fifth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (38)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 240° \, V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 240° \, V$		
Eq. (39)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0° \, V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0° \, V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (40)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		

Table 6: Example Calculation (Lens Point 5)	
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (41)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10\ \Omega) + (4 + j20\ \Omega) + (4 + j20\ \Omega)$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (42)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 240°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$
	$I_{sys} = 3{,}854\angle 125.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (43)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 125.5°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 125.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (44)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 92{,}953.7\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 125.5°\ A]$
	$V_S = 65{,}270.5\angle -99.4°\ V$
The impedance seen by the relay on Z_L.	
Eq. (45)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{65{,}270.5\angle -99.4°\ V}{3{,}854\angle 125.5°\ A}$
	$Z_{L-Relay} = -12.005 + j11.946\ \Omega$

Table 7: Example Calculation (Lens Point 6)			
This example is for calculating the impedance sixth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (46)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (47)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (48)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (49)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (50)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 240°\ V - 92{,}953.7\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 3{,}854\angle 137.1°\ A$		

Table 7: Example Calculation (Lens Point 6)	
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (51)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 137.1° \, A \times \frac{(4 + j20) \times 10^{10} \, \Omega}{(4 + j20) \, \Omega + (4 + j20) \times 10^{10} \, \Omega}$
	$I_L = 3{,}854\angle 137.1° \, A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (52)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240° \, V - [(2 + j10 \,) \, \Omega \times 3{,}854\angle 137.1° \, A]$
	$V_S = 98{,}265\angle -110.6° \, V$
The impedance seen by the relay on Z_L.	
Eq. (53)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle -110.6° \, V}{3{,}854\angle 137.1° \, A}$
	$Z_{L-Relay} = -9.676 + j23.59 \, \Omega$

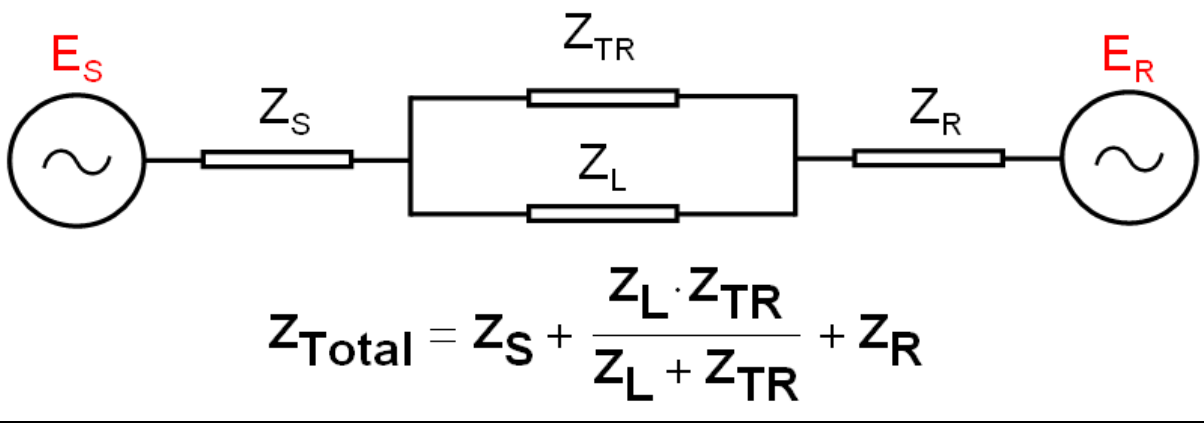


Figure 6: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and parallel transfer impedance Z_{TR}.

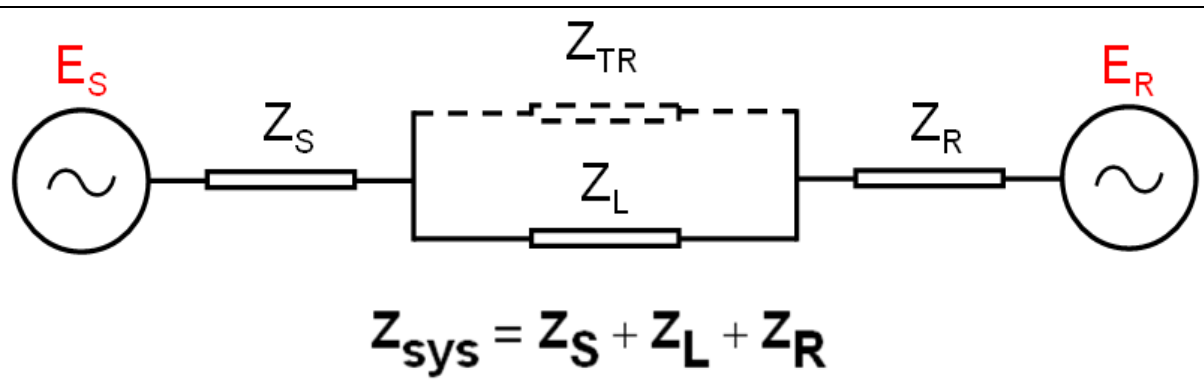


Figure 7: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, and line impedance Z_L with the parallel transfer impedance Z_{TR} removed.

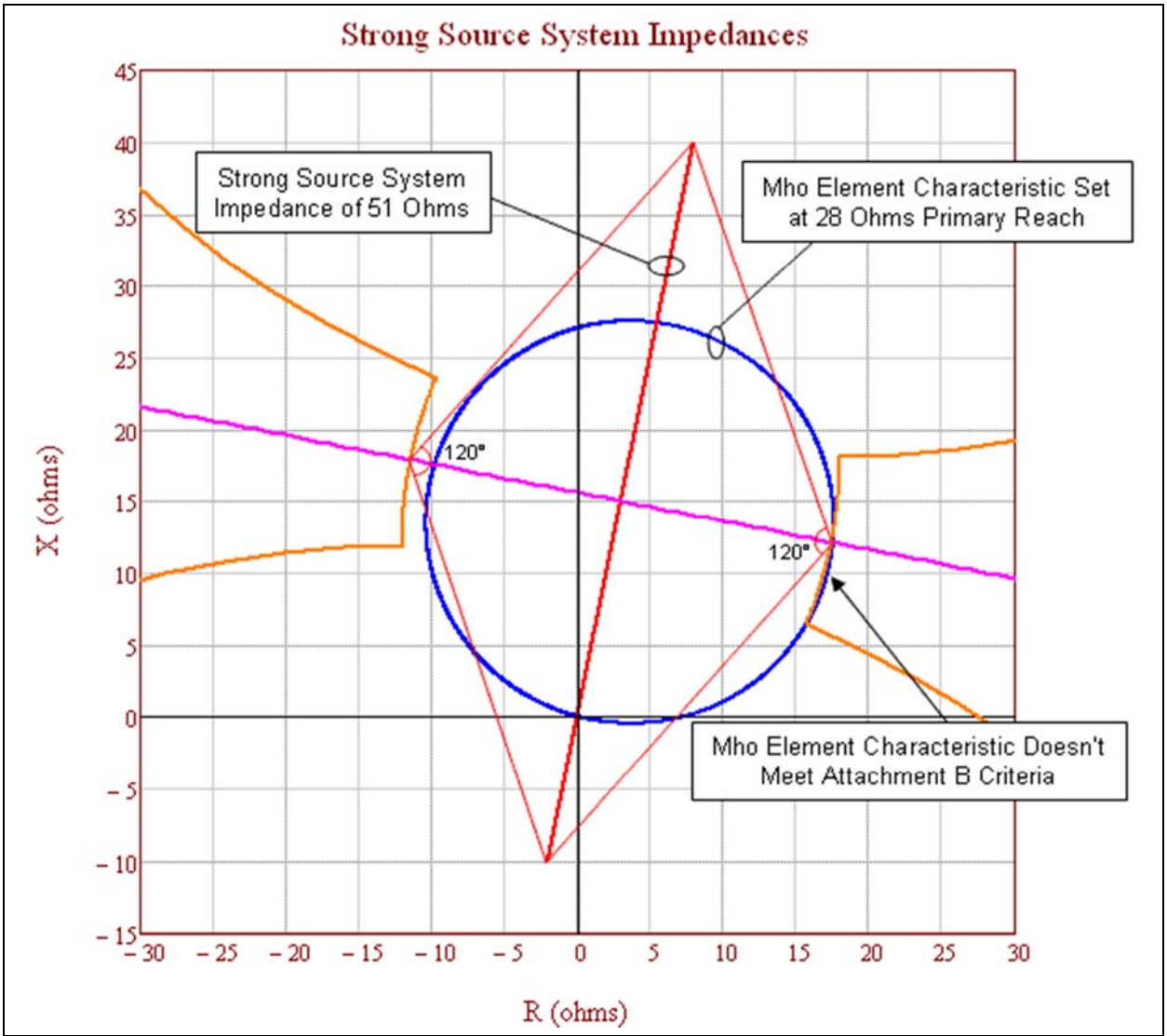


Figure 8: A strong-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) does not meet the PRC-026-1 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 8 above represents a heavily-loaded system with all generation in service and all transmission BES Elements in their normal operating state. The mho element characteristic (set at 137% of Z_L) extends into the unstable power swing region (i.e., the orange characteristic). Using the strongest source system is more conservative because it shrinks the unstable power swing region, bringing it closer to the mho element characteristic. This figure also graphically represents the effect of a system strengthening over time and this is the reason for re-evaluation if the relay has not been evaluated in the last five calendar years. Figure 9 below depicts a relay that meets the PRC-026-1 – Attachment B, Criterion A. Figure 8 depicts the same relay with the same setting five years later, where each source has strengthened by about 10% and now the same mho element characteristic does not meet Criterion A.

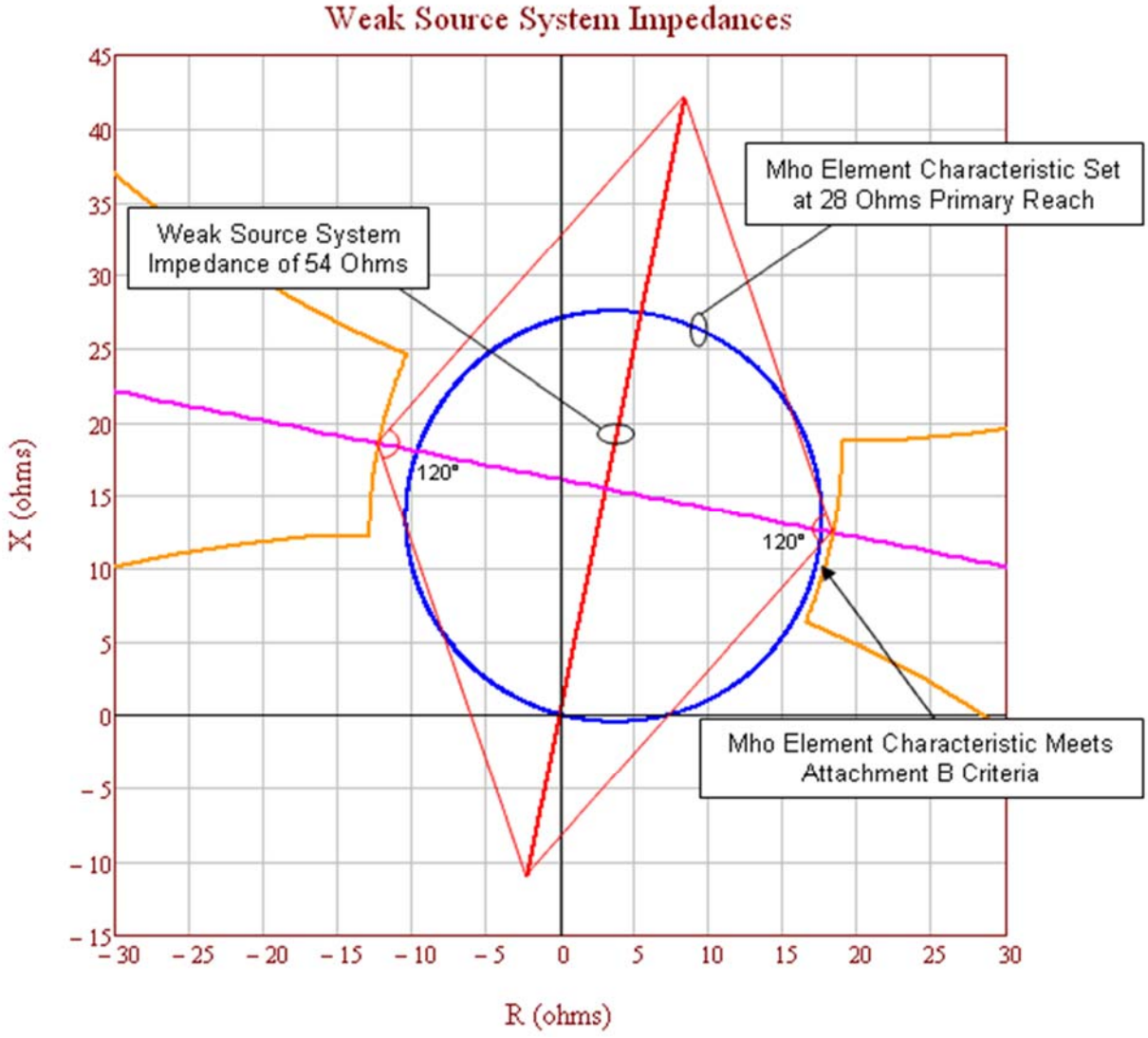


Figure 9: A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) meets the PRC-026-1 – Attachment B, Criterion A because it is completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 9 above represents a lightly-loaded system, using a minimum generation profile. The mho element characteristic (set at 137% of Z_L) does not extend into the unstable power swing region (i.e., the orange characteristic). Using a weaker source system expands the unstable power swing region away from the mho element characteristic.

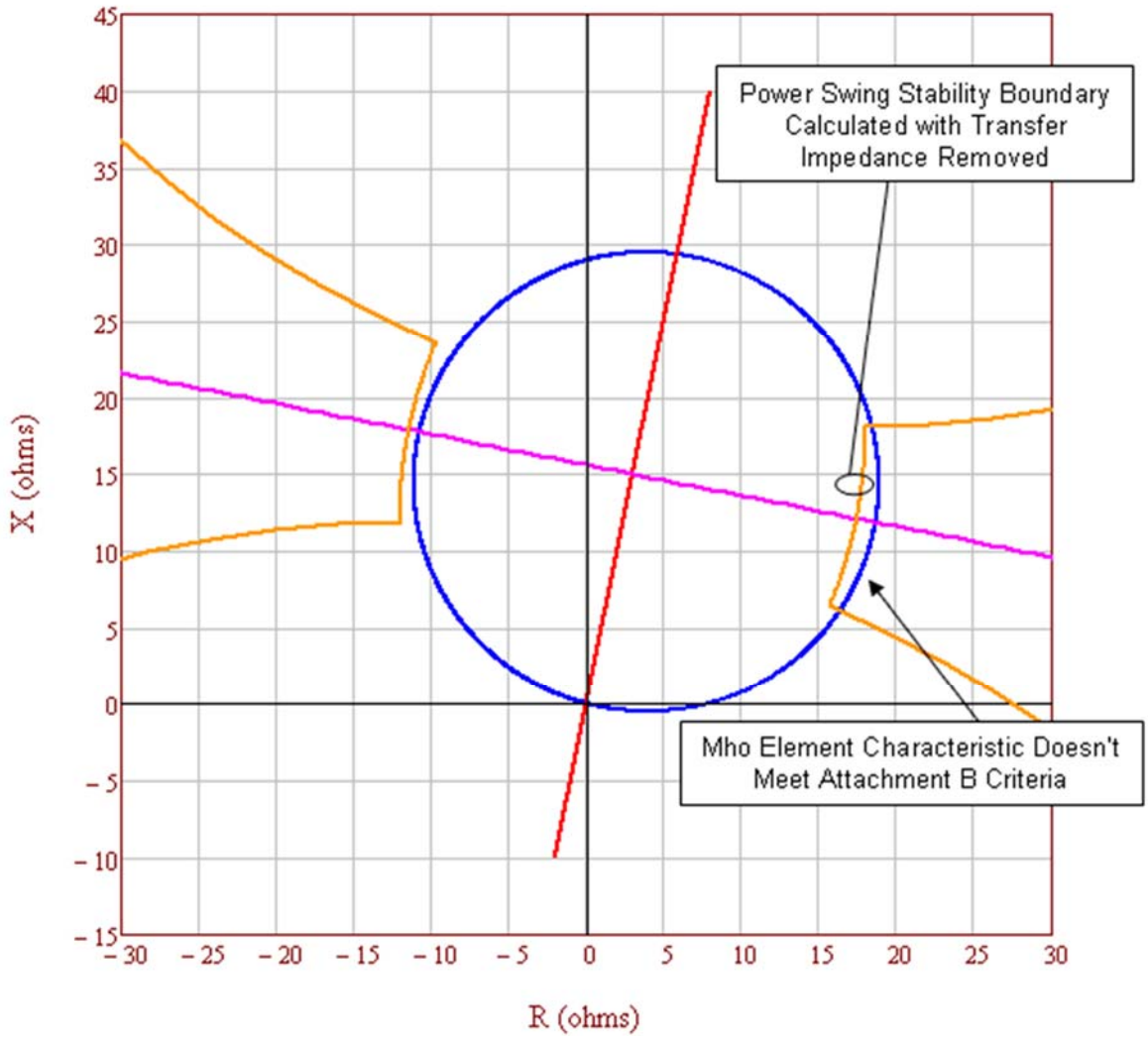


Figure 10: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance removed. This relay mho element characteristic (i.e., the blue circle) does not meet PRC-026-1 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region.

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
Calculations for the point at 120 degrees with equal source impedances. The total system current equals the line current. See Figure 10.	
Eq. (54)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$
	$E_S = 132{,}791\angle 120°\ V$

Table 8: Example Calculation (Parallel Transfer Impedance Removed)			
Eq. (55)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (56)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (57)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (58)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (59)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 71.3°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 71.3°\ A$		

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (60)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120° \, V - [(2 + j10\ \Omega) \times 4{,}511\angle 71.3° \, A]$
	$V_S = 95{,}757\angle 106.1° \, V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1° \, V}{4{,}511\angle 71.3° \, A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

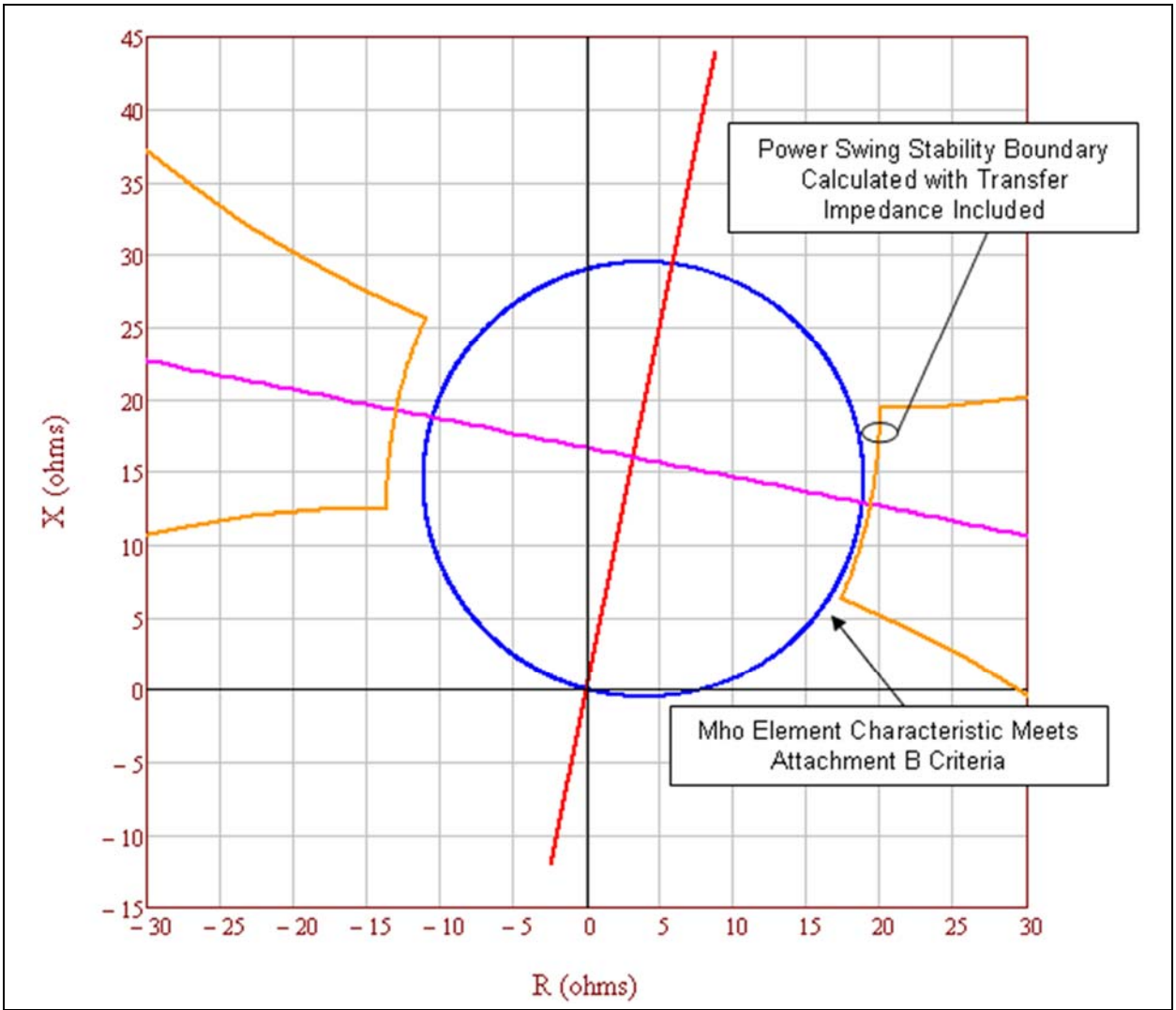


Figure 11: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance included causing the mho element characteristic (i.e., the blue circle) to appear to meet the PRC-026-1 – Attachment B, Criterion A because it is completely contained within the unstable power swing region. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-1 – Attachment B, Criterion A.

In Figure 11 above, the parallel transfer impedance is 5 times the line impedance. The unstable power swing region has expanded out beyond the mho element characteristic due to the infeed effect from the parallel current through the parallel transfer impedance, thus allowing the mho element characteristic to appear to meet the PRC-026-1 – Attachment B, Criterion A. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-1 – Attachment B, Criterion A.

Table 9: Example Calculation (Parallel Transfer Impedance Included)			
Calculations for the point at 120 degrees with equal source impedances. The total system current does not equal the line current. See Figure 11.			
Eq. (62)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (63)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 5$		
	$Z_{TR} = (4 + j20)\ \Omega \times 5$		
	$Z_{TR} = 20 + j100\ \Omega$		
Total impedance between the generators.			
Eq. (64)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{(4 + j20)\ \Omega \times (20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$		
	$Z_{total} = 3.333 + j16.667\ \Omega$		
Total system impedance.			
Eq. (65)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (3.333 + j16.667)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 9.333 + j46.667\ \Omega$		
Total system current from sending-end source.			
Eq. (66)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{9.333 + j46.667\ \Omega}$		

Table 9: Example Calculation (Parallel Transfer Impedance Included)	
	$I_{sys} = 4{,}833\angle 71.3° \; A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (67)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}833\angle 71.3° \; A \times \frac{(20 + j100)\;\Omega}{(4 + j20)\;\Omega + (20 + j100)\;\Omega}$
	$I_L = 4{,}027.4\angle 71.3° \; A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (68)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120° \; V - [(2 + j10\;\Omega) \times 4{,}833\angle 71.3° \; A]$
	$V_S = 93{,}417\angle 104.7° \; V$
The impedance seen by the relay on Z_L.	
Eq. (69)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{93{,}417\angle 104.7° \; V}{4{,}027\angle 71.3° \; A}$
	$Z_{L-Relay} = 19.366 + j12.767\;\Omega$

Table 10: Percent Increase of a Lens Due To Parallel Transfer Impedance.	
The following demonstrates the percent size increase of the lens characteristic for Z_{TR} in multiples of Z_L with the parallel transfer impedance included.	
Z_{TR} in multiples of Z_L	Percent increase of lens with equal EMF sources (Infinite source as reference)
Infinite	N/A
1000	0.05%
100	0.46%
10	4.63%
5	9.27%
2	23.26%
1	46.76%
0.5	94.14%
0.25	189.56%

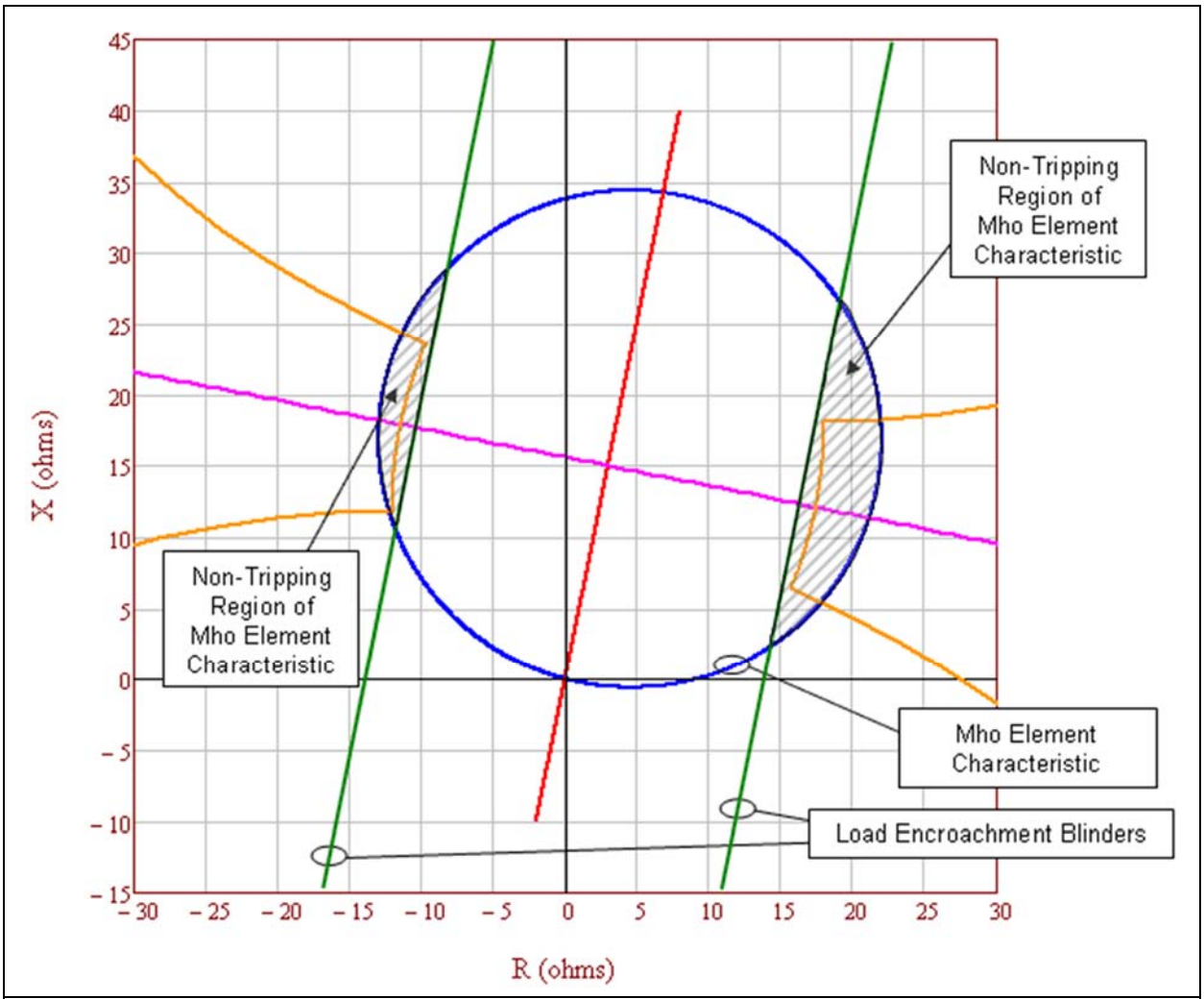


Figure 12: The tripping portion of the mho element characteristic (i.e., the blue circle) not blocked by load encroachment (i.e., the parallel green lines) is completely contained within the unstable power swing region (i.e., the orange characteristic). Therefore, the mho element characteristic meets the PRC-026-1 – Attachment B, Criterion A.

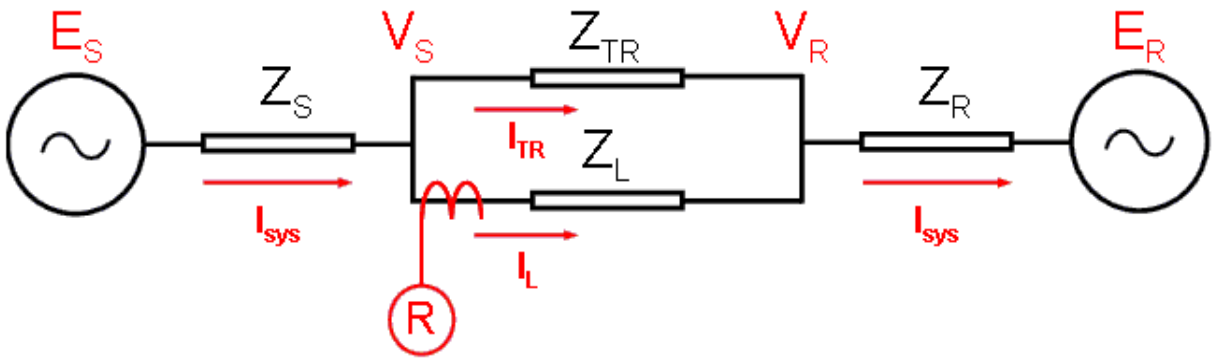


Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

Table 11: Calculations (System Apparent Impedance in the forward direction)				
The following equations are provided for calculating the apparent impedance back to the E_R source voltage as seen by relay R. Infeed equations from V_S to source E_R where $E_R = 0$. See Figure 13.				
Eq. (70)	$I_L = \frac{V_S - V_R}{Z_L}$			
Eq. (71)	$I_{sys} = \frac{V_R - E_R}{Z_R}$			
Eq. (72)	$I_{sys} = I_L + I_{TR}$			
Eq. (73)	$I_{sys} = \frac{V_R}{Z_R}$	Since $E_R = 0$	Rearranged:	$V_R = I_{sys} \times Z_R$
Eq. (74)	$I_L = \frac{V_S - I_{sys} \times Z_R}{Z_L}$			
Eq. (75)	$I_L = \frac{V_S - [(I_L + I_{TR}) \times Z_R]}{Z_L}$			
Eq. (76)	$V_S = (I_L \times Z_L) + (I_L \times Z_R) + (I_{TR} \times Z_R)$			
Eq. (77)	$Z_{Relay} = \frac{V_S}{I_L} = Z_L + Z_R + \frac{I_{TR} \times Z_R}{I_L} = Z_L + Z_R \times \left(1 + \frac{I_{TR}}{I_L}\right)$			
Eq. (78)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$			
Eq. (79)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$			

Table 11: Calculations (System Apparent Impedance in the forward direction)	
Eq. (80)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$
The infeed equations shows the impedance in front of the relay R (Figure 13) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.	
Eq. (81)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$

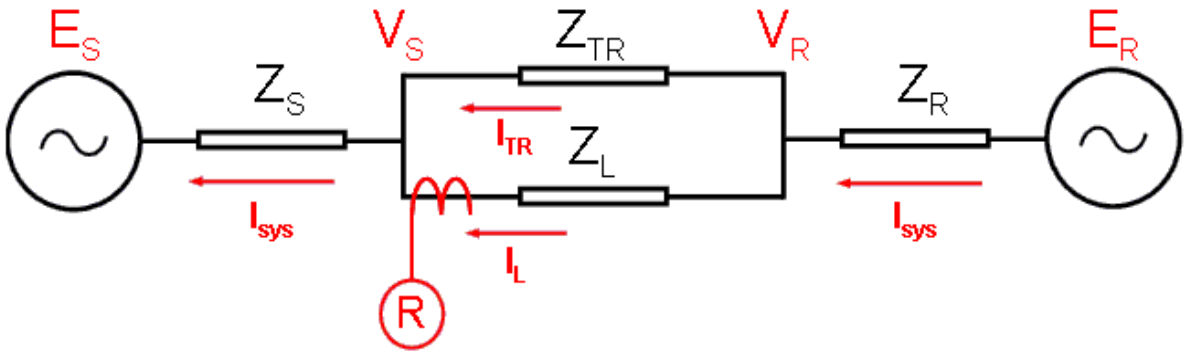


Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)				
The following equations are provided for calculating the apparent impedance back to the E_S source voltage as seen by relay R. Infeed equations from V_R back to source E_S where $E_S = 0$. See Figure 14.				
Eq. (82)	$I_L = \frac{V_R - V_S}{Z_L}$			
Eq. (83)	$I_{sys} = \frac{V_S - E_S}{Z_S}$			
Eq. (84)	$I_{sys} = I_L + I_{TR}$			
Eq. (85)	$I_{sys} = \frac{V_S}{Z_S}$	Since $E_s = 0$	Rearranged:	$V_S = I_{sys} \times Z_S$
Eq. (86)	$I_L = \frac{V_R - I_{sys} \times Z_S}{Z_L}$			

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)		
Eq. (87)	$I_L = \frac{V_R - [(I_L + I_{TR}) \times Z_S]}{Z_L}$	
Eq. (88)	$V_R = (I_L \times Z_L) + (I_L \times Z_S) + (I_{TR} \times Z_{RS})$	
Eq. (89)	$Z_{Relay} = \frac{V_R}{I_L} = Z_L + Z_S + \frac{I_{TR} \times Z_S}{I_L} = Z_L + Z_S \times \left(1 + \frac{I_{TR}}{I_L}\right)$	
Eq. (90)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$	
Eq. (91)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$	
Eq. (92)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$	
The infeed equations shows the impedance behind relay R (Figure 14) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.		
Eq. (93)	$Z_{Relay} = Z_L + Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	As seen by relay R at the receiving-end of the line.
Eq. (94)	$Z_{Relay} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	Subtract Z_L for relay R impedance as seen at sending-end of the line.

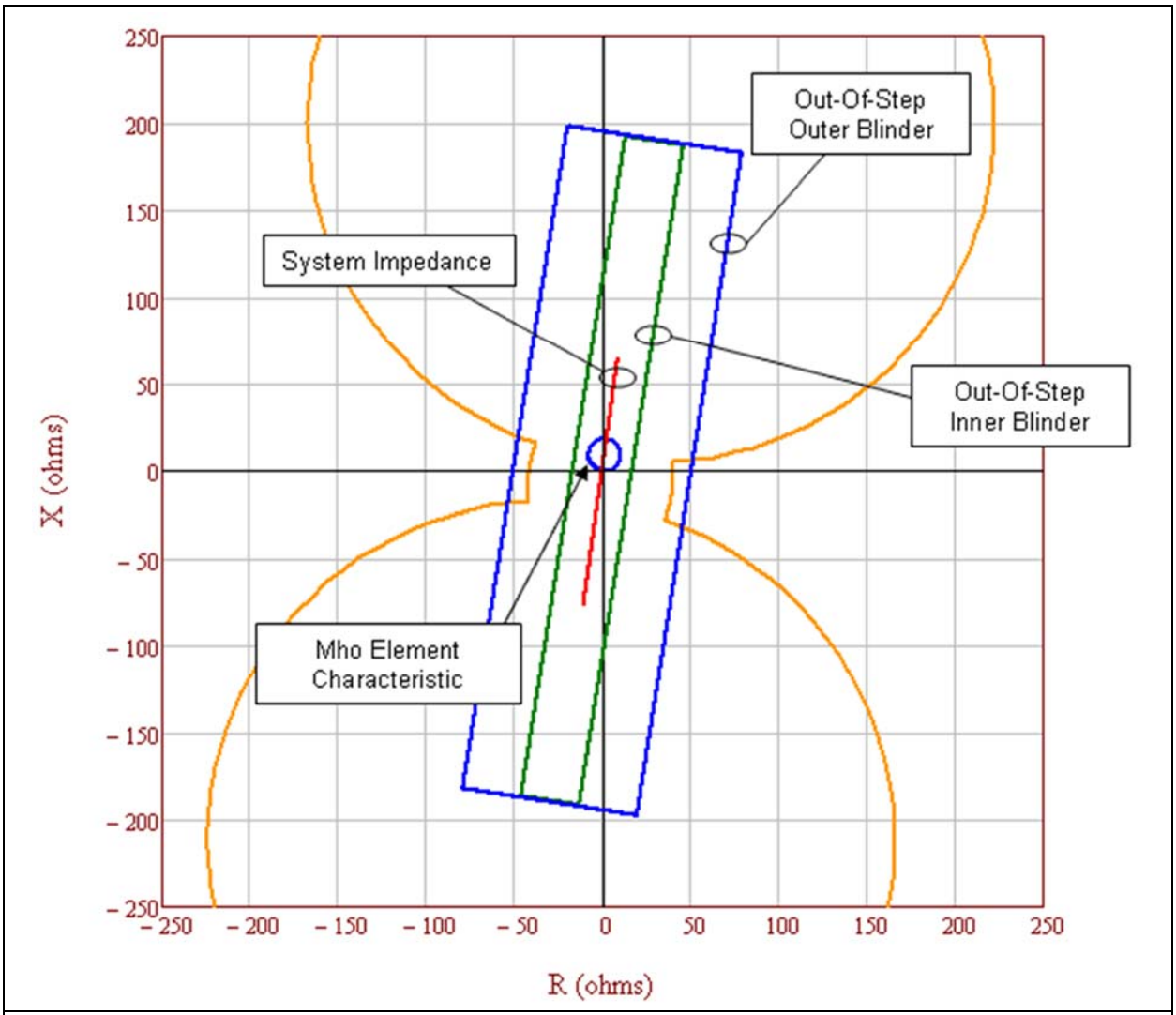


Figure 15: Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-1 – Attachment B, Criterion A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the unstable power swing region (i.e., the orange characteristic), it meets the PRC-026-1 – Attachment B, Criterion A.

Table 13: Example Calculation (Voltage Ratios)			
These calculations are based on the loss-of-synchronism characteristics for the cases of N < 1 and N > 1 as found in the *Application of Out-of-Step Blocking and Tripping Relays*, GER-3180, p. 12, Figure 3.[18] The GE illustration shows the formulae used to calculate the radius and center of the circles that make up the ends of the portion of the lens.			
Voltage ratio equations, source impedance equation with infeed formulae applied, and circle equations.			
Given:	$E_S = 0.7$	$E_R = 1.0$	
Eq. (95)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{0.7}{1.0} = 0.7$		
The total system impedance as seen by the relay with infeed formulae applied.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
	$Z_{TR} = (4 + j20) \times 10^{10}\ \Omega$		
Eq. (96)	$Z_{sys} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right) + \left[Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right]$		
	$Z_{sys} = 10 + j50\ \Omega$		
The calculated coordinates of the lower loss-of-synchronism circle center.			
Eq. (97)	$Z_{C1} = -\left[Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] - \left[\frac{N^2 \times Z_{sys}}{1 - N^2}\right]$		
	$Z_{C1} = -\left[(2 + j10)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] - \left[\frac{0.7^2 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right]$		
	$Z_{C1} = -11.608 - j58.039\ \Omega$		
The calculated radius of the lower loss-of-synchronism circle.			
Eq. (98)	$r_a = \left\lvert \frac{N \times Z_{sys}}{1 - N^2} \right\rvert$		
	$r_a = \left\lvert \frac{0.7 \times (10 + j50)\ \Omega}{1 - 0.7^2} \right\rvert$		
	$r_a = 69.987\ \Omega$		
The calculated coordinates of the upper loss-of-synchronism circle center.			
Given:	$E_S = 1.0$	$E_R = 0.7$	

[18] http://store.gedigitalenergy.com/faq/Documents/Alps/GER-3180.pdf

Table 13: Example Calculation (Voltage Ratios)	
Eq. (99)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{1.0}{0.7} = 1.43$
Eq. (100)	$Z_{C2} = Z_L + \left[Z_R \times \left(1 + \frac{Z_L}{Z_{TR}} \right) \right] + \left[\frac{Z_{sys}}{N^2 - 1} \right]$
	$Z_{C2} = 4 + j20\ \Omega + \left[(4 + j20)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega} \right) \right] + \left[\frac{(10 + j50)\ \Omega}{1.43^2 - 1} \right]$
	$Z_{C2} = 17.608 + j88.039\ \Omega$
The calculated radius of the upper loss-of-synchronism circle.	
Eq. (101)	$r_b = \left\lvert \frac{N \times Z_{sys}}{N^2 - 1} \right\rvert$
	$r_b = \left\lvert \frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1} \right\rvert$
	$r_b = 69.987\ \Omega$

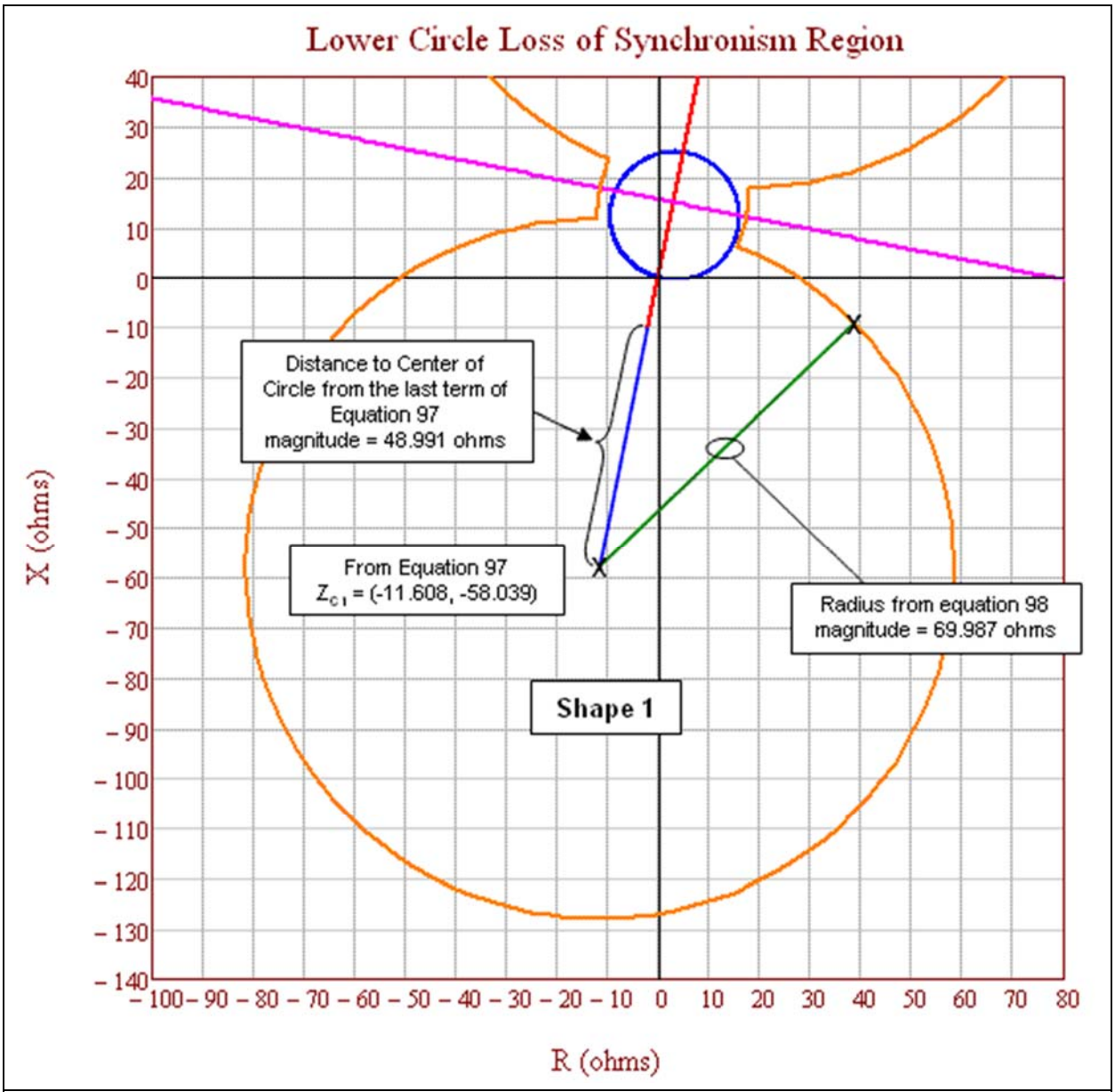


Figure 15a: Lower circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

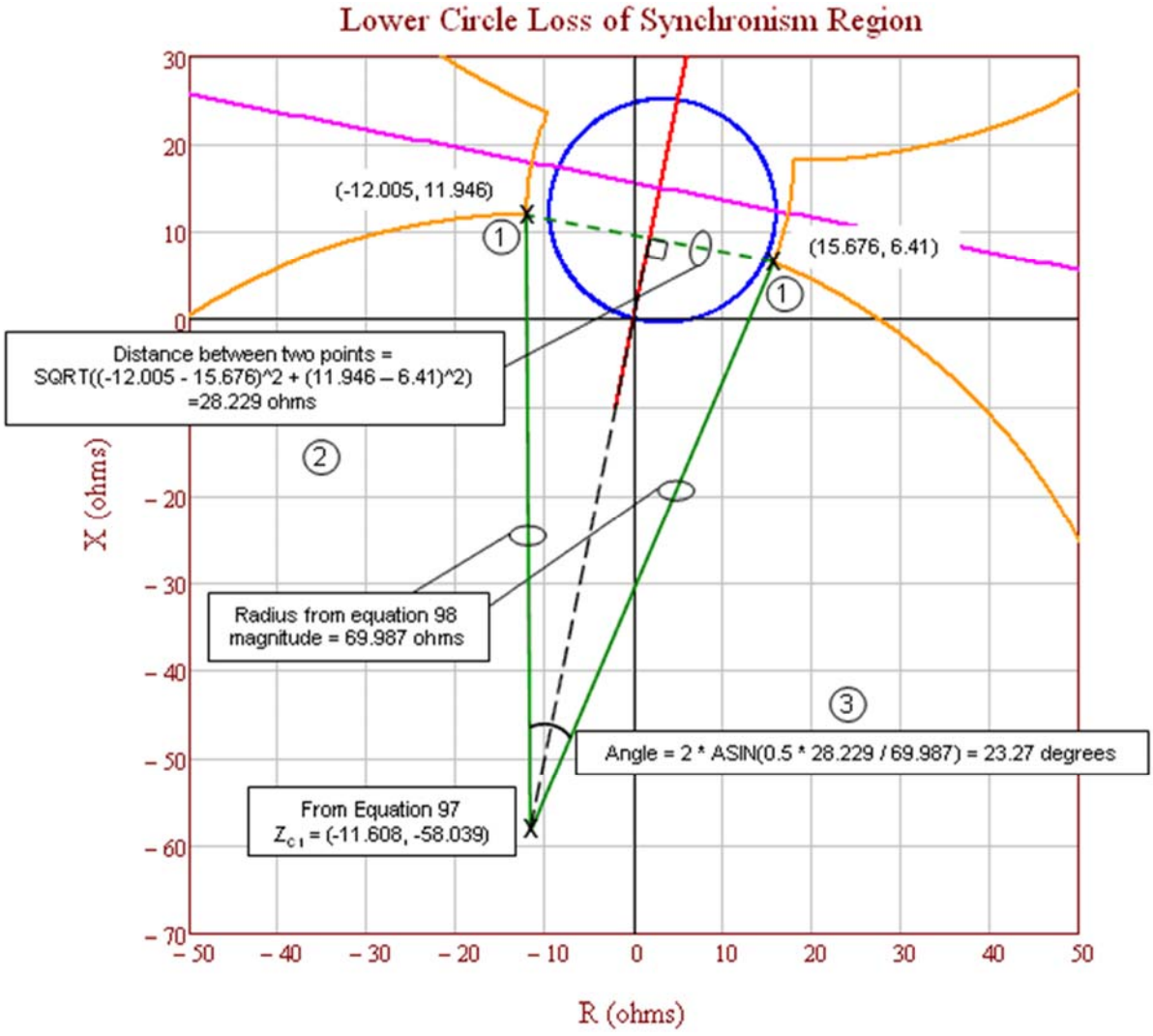


Figure 15b: Lower circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the lower circle loss-of-synchronism points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 0.7 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two lower circle loss-of-synchronism points identified in Step 1. 3) Calculate the angle of arc that connects the two lower circle loss-of-synchronism points identified in Step 1.

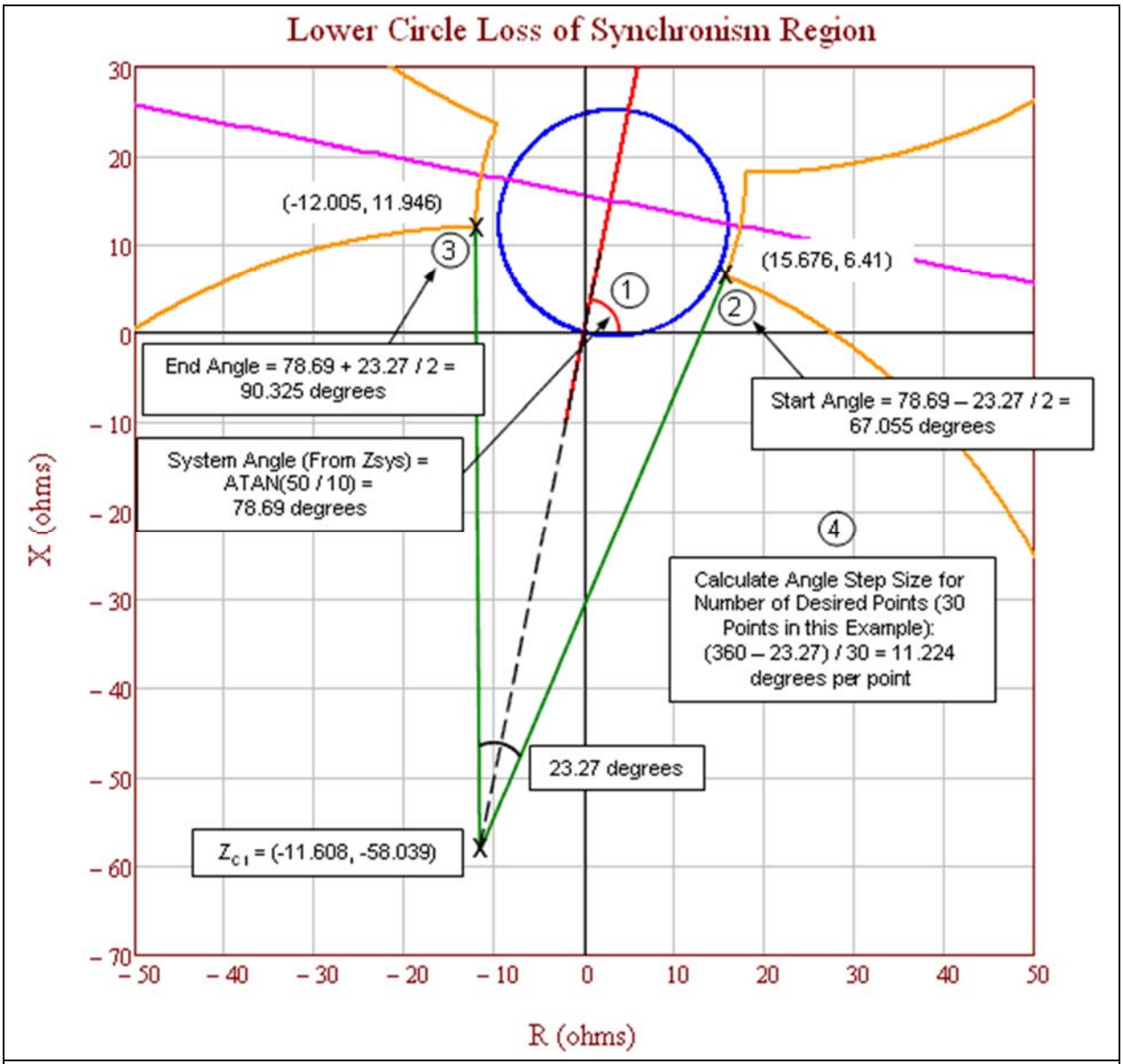


Figure 15c: Lower circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

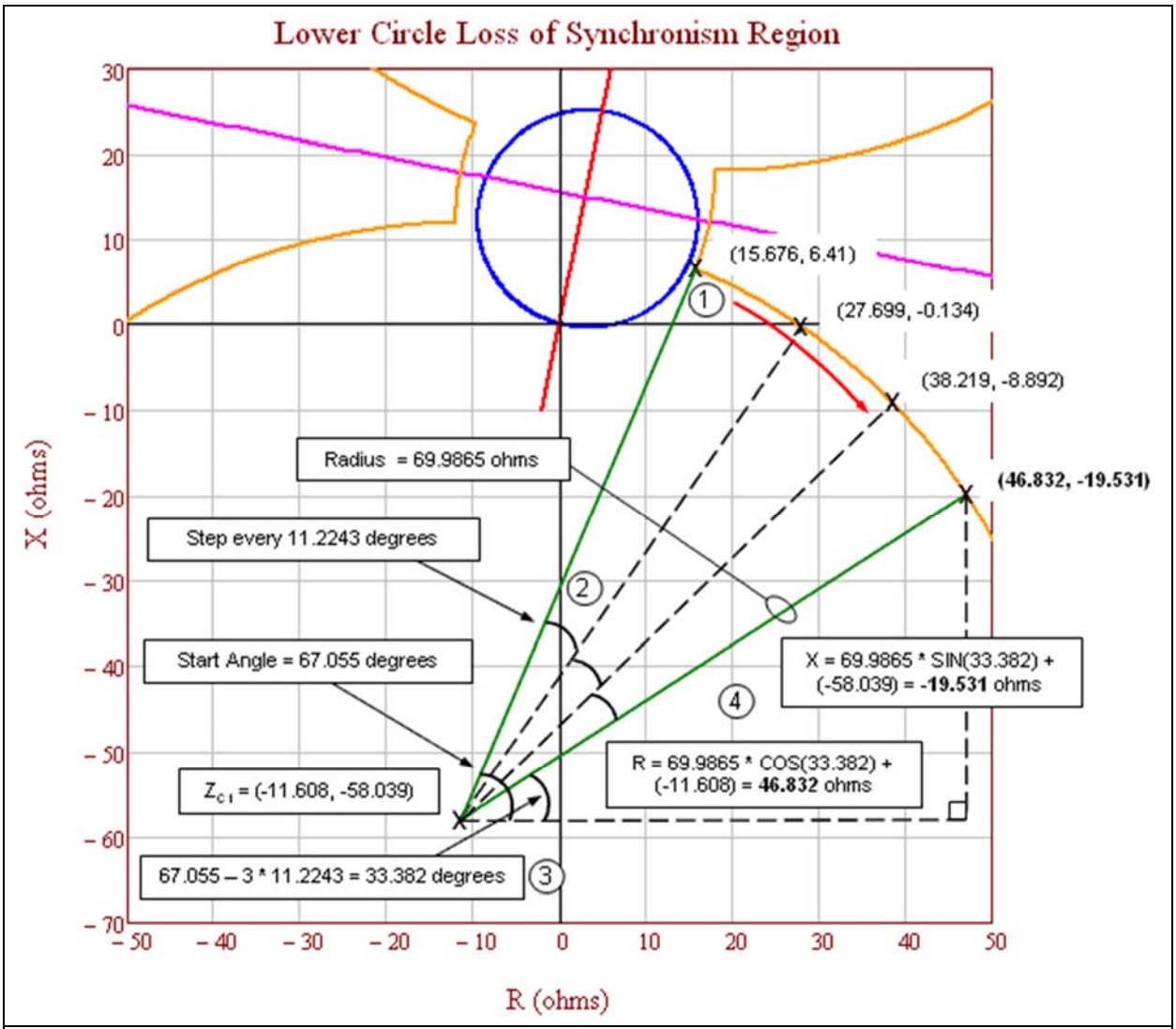


Figure 15d: Lower circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R–X coordinates.

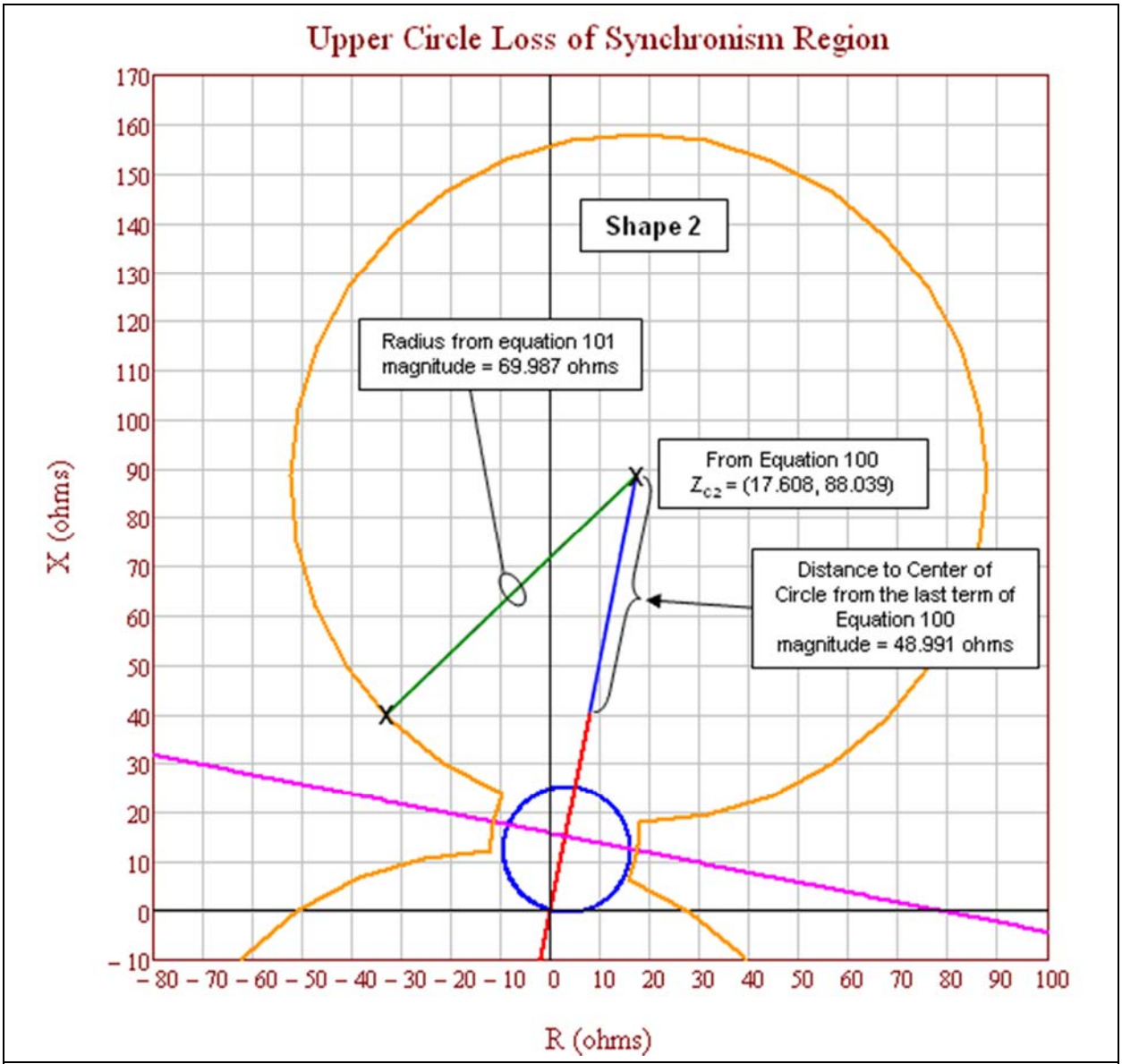


Figure 15e: Upper circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

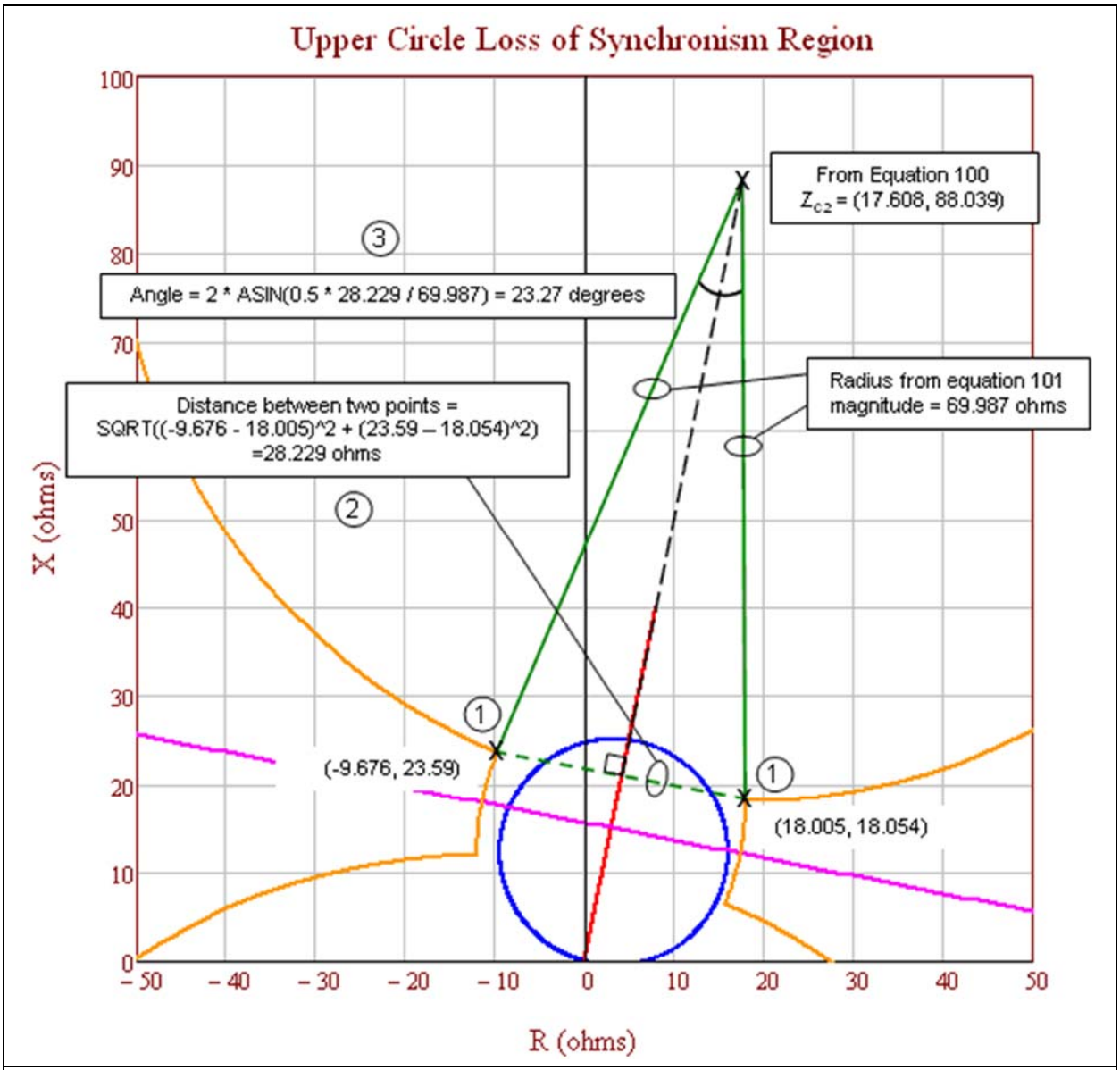


Figure 15f: Upper circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the upper circle points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 1.43 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two upper circle points identified in Step 1. 3) Calculate the angle of arc that connects the two upper circle points identified in Step 1.

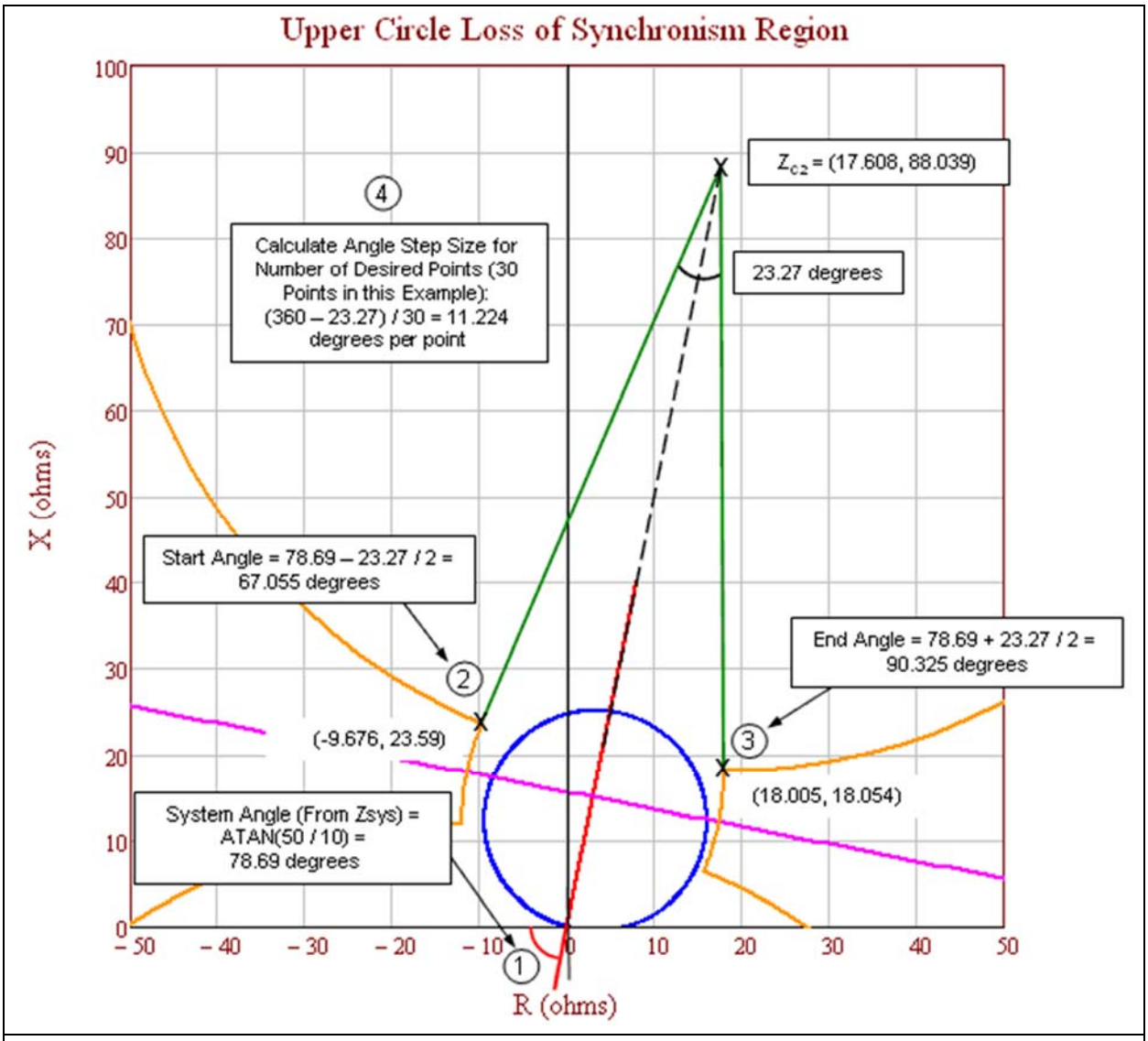


Figure 15g: Upper circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

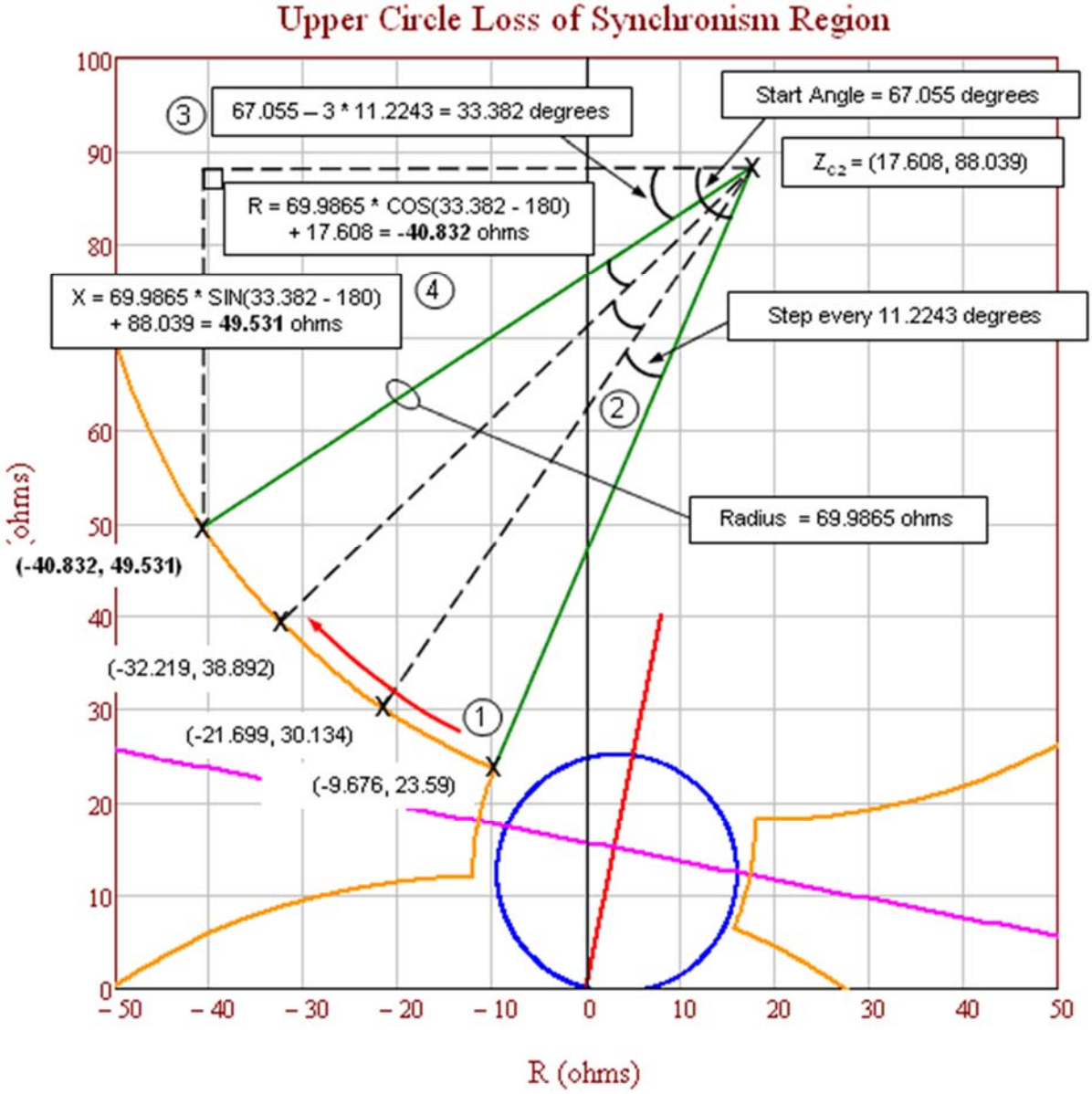


Figure 15h: Upper circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R-X coordinates.

Lower Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	15.676	6.41
55.831	27.699	-0.134
44.606	38.219	-8.892
33.382	**46.832**	**-19.531**
22.158	53.21	-31.643
10.933	57.108	-44.765
359.709	58.378	-58.395
348.485	56.97	-72.011
337.26	52.939	-85.092
326.036	46.438	-97.139
314.812	37.717	-107.69
303.587	27.109	-116.341
292.363	15.02	-122.762
281.139	1.913	-126.707
269.914	-11.712	-128.026
258.69	-25.333	-126.667
247.466	-38.429	-122.682
236.241	-50.499	-116.225
225.017	-61.081	-107.542
213.793	-69.771	-96.965
202.568	-76.235	-84.899
191.344	-80.227	-71.806
180.12	-81.594	-58.185
168.895	-80.284	-44.56
157.671	-76.347	-31.45
146.447	-69.933	-19.357
135.222	-61.288	-8.744
123.998	-50.742	-0.016
112.774	-38.699	6.491
101.549	-25.62	10.53
90.325	-12.005	11.946

Upper Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	-9.676	23.59
55.831	-21.699	30.134
44.606	-32.219	38.892
33.382	**-40.832**	**49.531**
22.158	-47.21	61.643
10.933	-51.108	74.765
359.709	-52.378	88.395
348.485	-50.97	102.011
337.26	-46.939	115.092
326.036	-40.438	127.139
314.812	-31.717	137.69
303.587	-21.109	146.341
292.363	-9.02	152.762
281.139	4.087	156.707
269.914	17.712	158.026
258.69	31.333	156.667
247.466	44.429	152.682
236.241	56.499	146.225
225.017	67.081	137.542
213.793	75.771	126.965
202.568	82.235	114.899
191.344	86.227	101.806
180.12	87.594	88.185
168.895	86.284	74.56
157.671	82.347	61.45
146.447	75.933	49.357
135.222	67.288	38.744
123.998	56.742	30.016
112.774	44.699	23.509
101.549	31.62	19.47
90.325	18.005	18.054

Figure 15i: Full tables of calculated lower and upper loss-of-synchronism circle coordinates. The highlighted row is the detailed calculated points in Figures 15d and 15h.

Application Specific to Criterion B

The PRC-026-1 – Attachment B, Criterion B evaluates overcurrent elements used for tripping. The same criteria as PRC-026-1 – Attachment B, Criterion A is used except for an additional criterion (No. 4) that calculates a current magnitude based upon generator internal voltage of 1.05 per unit. A value of 1.05 per unit generator voltage is used to establish a minimum pickup current value for overcurrent relays that have a time delay less than 15 cycles. The sending-end and receiving-end voltages are established at 1.05 per unit at 120 degree system separation angle. The 1.05 per unit is the typical upper end of the operating voltage, which is also consistent with the maximum power

transfer calculation using actual system source impedances in the PRC-023 NERC Reliability Standard. The formulas used to calculate the current are in Table 14 below.

Table 14: Example Calculation (Overcurrent)

This example is for a 230 kV line terminal with a directional instantaneous phase overcurrent element set to 50 amps secondary times a CT ratio of 160:1 that equals 8,000 amps, primary. The following calculation is where V_S equals the base line-to-ground sending-end generator source voltage times 1.05 at an angle of 120 degrees, V_R equals the base line-to-ground receiving-end generator internal voltage times 1.05 at an angle of 0 degrees, and Z_{sys} equals the sum of the sending-end source, line, and receiving-end source impedances in ohms.

Here, the instantaneous phase setting of 8,000 amps is greater than the calculated system current of 5,716 amps; therefore, it meets PRC-026-1 – Attachment B, Criterion B.

Eq. (102)	$V_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 1.05$		
	$V_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 1.05$		
	$V_S = 139{,}430\angle 120°\ V$		
Receiving-end generator terminal voltage.			
Eq. (103)	$V_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 1.05$		
	$V_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 1.05$		
	$V_R = 139{,}430\angle 0°\ V$		
The total impedance of the system (Z_{sys}) equals the sum of the sending-end source impedance (Z_S), the impedance of the line (Z_L), and receiving-end impedance (Z_R) in ohms.			
Given:	$Z_S = 3 + j26\ \Omega$	$Z_L = 1.3 + j8.7\ \Omega$	$Z_R = 0.3 + j7.3\ \Omega$
Eq. (104)	$Z_{sys} = Z_S + Z_L + Z_R$		
	$Z_{sys} = (3 + j26)\ \Omega + (1.3 + j8.7)\ \Omega + (0.3 + j7.3)\ \Omega$		
	$Z_{sys} = 4.6 + j42\ \Omega$		
Total system current.			
Eq. (105)	$I_{sys} = \frac{(V_S - V_R)}{Z_{sys}}$		
	$I_{sys} = \frac{(139{,}430\angle 120°\ V - 139{,}430\angle 0°\ V)}{(4.6 + j42)\ \Omega}$		
	$I_{sys} = 5{,}715.82\angle 66.25°\ A$		

Application Specific to Three-Terminal Lines

If a three-terminal line is identified as an Element that is susceptible to a power swing based on Requirement R1, the load-responsive protective relays at each end of the three-terminal line must be evaluated.

As shown in Figure 15j, the source impedances at each end of the line can be obtained from the similar short circuit calculation as for the two-terminal line (assuming the parallel transfer impedances are ignored).

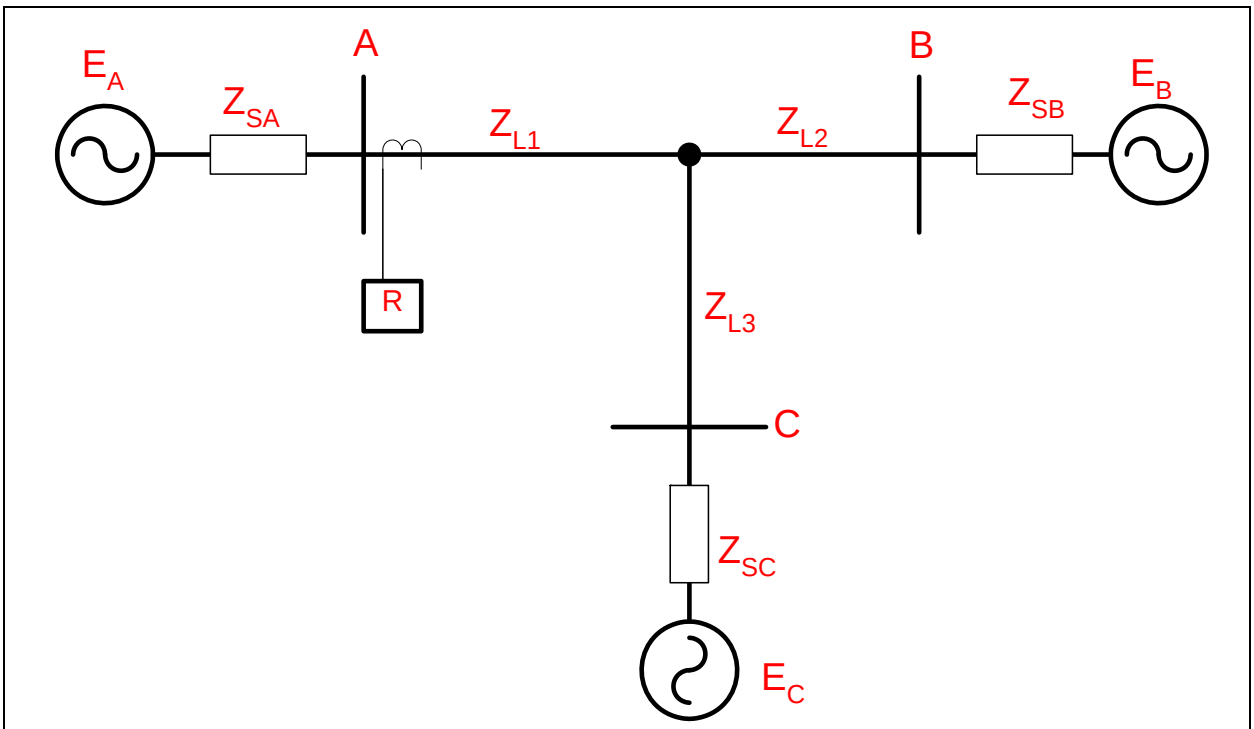


Figure 15j: Three-terminal line. To evaluate the load-responsive protective relays on the three-terminal line at Terminal A, the circuit in Figure 15j is first reduced to the equivalent circuit shown in Figure 15k. The evaluation process for the load-responsive protective relays on the line at Terminal A will now be the same as that of the two-terminal line.

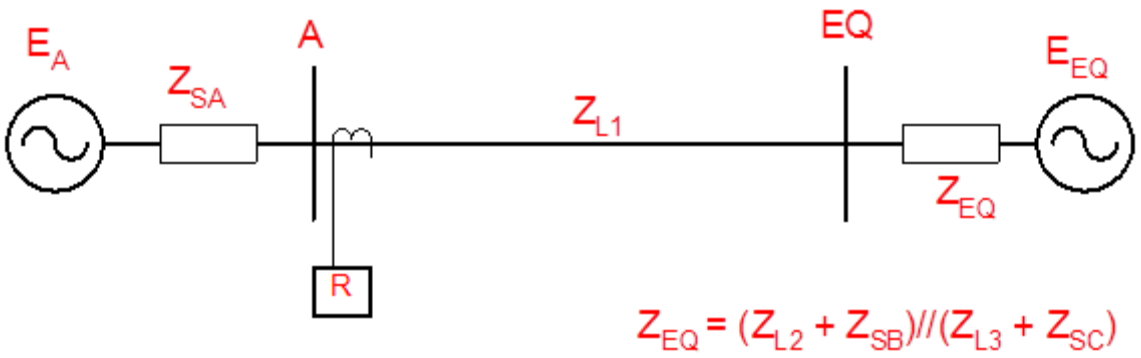


Figure 15k: Three-terminal line reduced to a two-terminal line.

Application to Generation Elements

As with transmission BES Elements, the determination of the apparent impedance seen at an Element located at, or near, a generation Facility is complex for power swings due to various interdependent quantities. These variances in quantities are caused by changes in machine internal voltage, speed governor action, voltage regulator action, the reaction of other local generators, and the reaction of other interconnected transmission BES Elements as the event progresses through the time domain. Though transient stability simulations may be used to determine the apparent impedance for verifying load-responsive relay settings,[19,20] Requirement R2, PRC-026-1 – Attachment B, Criteria A and B provides a simplified method for evaluating the load-responsive protective relay's susceptibility to tripping in response to a stable power swing without requiring stability simulations.

In general, the electrical center will be in the transmission system for cases where the generator is connected through a weak transmission system (high external impedance). In other cases where the generator is connected through a strong transmission system, the electrical center could be inside the unit connected zone.[21] In either case, load-responsive protective relays connected at the generator terminals or at the high-voltage side of the generator step-up (GSU) transformer may be challenged by power swings. Relays that may be challenged by power swings will be determined by the Planning Coordinator in Requirement R1 or by the Generator Owner after becoming aware of a generator, transformer, or transmission line BES Element that tripped[22] in response to a stable or unstable power swing due to the operation of its protective relay(s) in Requirement R2.

[19] Donald Reimert, *Protective Relaying for Power Generation Systems*, Boca Raton, FL, CRC Press, 2006.

[20] Prabha Kundur, *Power System Stability and Control*, EPRI, McGraw Hill, Inc., 1994.

[21] Ibid, Kundur.

[22] See Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing,"

Voltage controlled time-overcurrent and voltage-restrained time-overcurrent relays are excluded from this standard. When these relays are set based on equipment permissible overload capability, their operating times are much greater than 15 cycles for the current levels observed during a power swing.

Instantaneous overcurrent, time-overcurrent, and definite-time overcurrent relays with a time delay of less than 15 cycles for the current levels observed during a power swing are applicable and are required to be evaluated for identified Elements.

The generator loss-of-field protective function is provided by impedance relay(s) connected at the generator terminals. The settings are applied to protect the generator from a partial or complete loss of excitation under all generator loading conditions and, at the same time, be immune to tripping on stable power swings. It is more likely that the loss-of-field relay would operate during a power swing when the automatic voltage regulator (AVR) is in manual mode rather than when in automatic mode.[23] Figure 16 illustrates the loss-of-field relay in the R-X plot, which typically includes up to three zones of protection.

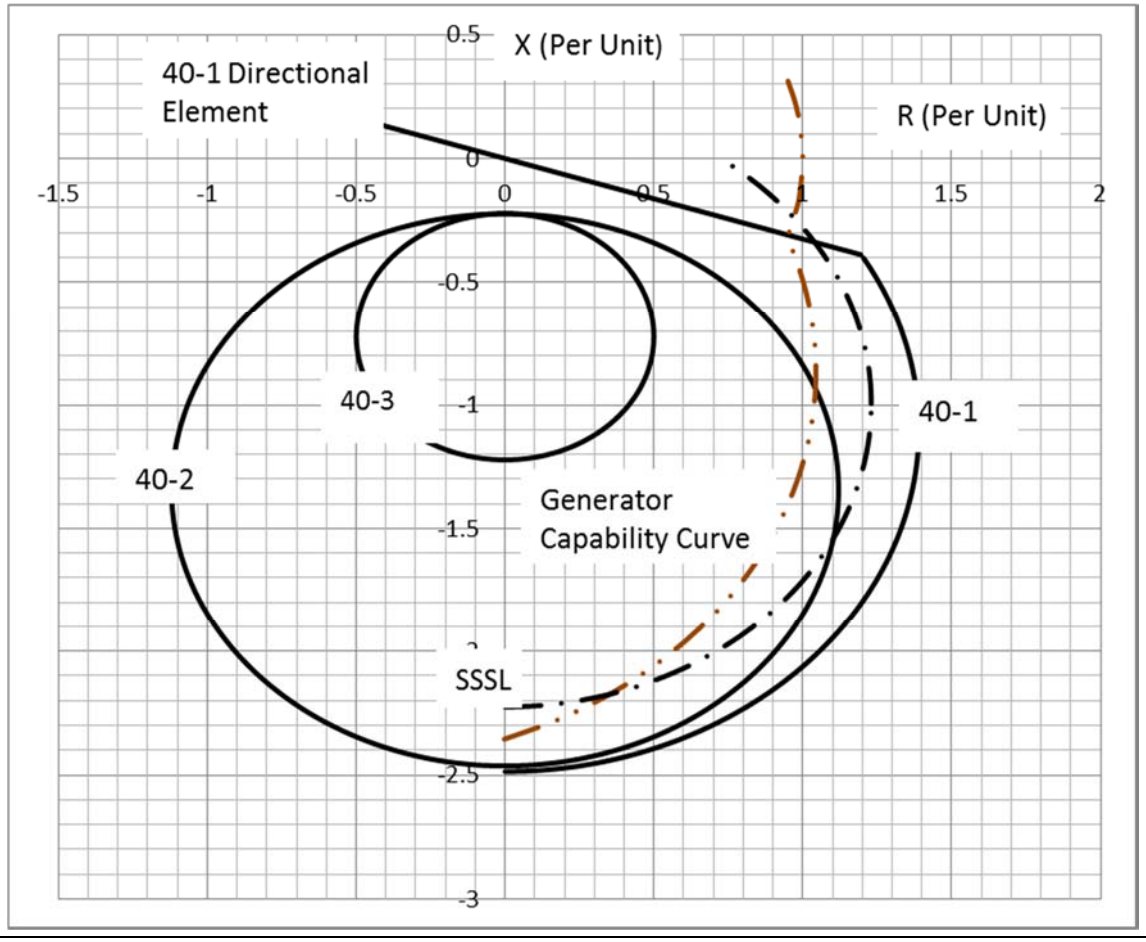


Figure 16: An R-X graph of typical impedance settings for loss-of-field relays.

[23] John Burdy, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

Loss-of-field characteristic 40-1 has a wider impedance characteristic (positive offset) than characteristic 40-2 or characteristic 40-3 and provides additional generator protection for a partial loss of field or a loss of field under low load (less than 10% of rated). The tripping logic of this protection scheme is established by a directional contact, a voltage setpoint, and a time delay. The voltage and time delay add security to the relay operation for stable power swings. Characteristic 40-3 is less sensitive to power swings than characteristic 40-2 and is set outside the generator capability curve in the leading direction. Regardless of the relay impedance setting, PRC-019[24] requires that the "in-service limiters operate before Protection Systems to avoid unnecessary trip" and "in-service Protection System devices are set to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits." Time delays for tripping associated with loss-of-field relays[25,26] have a range from 15 cycles for characteristic 40-2 to 60 cycles for characteristic 40-1 to minimize tripping during stable power swings. In PRC-026-1, 15 cycles establishes a threshold for applicability; however, it is the responsibility of the Generator Owner to establish settings that provide security against stable power swings and, at the same time, dependable protection for the generator.

The simple two-machine system circuit (method also used in the Application to Transmission Elements section) is used to analyze the effect of a power swing at a generator facility for load-responsive relays. In this section, the calculation method is used for calculating the impedance seen by the relay connected at a point in the circuit.[27] The electrical quantities used to determine the apparent impedance plot using this method are generator saturated transient reactance (X'_d), GSU transformer impedance (X_{GSU}), transmission line impedance (Z_L), and the system equivalent (Z_e) at the point of interconnection. All impedance values are known to the Generator Owner except for the system equivalent. The system equivalent is obtainable from the Transmission Owner. The sending-end and receiving-end source voltages are varied from 0.0 to 1.0 per unit to form the lens shape portion of the unstable power swing region. The voltage range of 0.7 to 1.0 results in a ratio range from 0.7 to 1.43. This ratio range is used to form the lower and upper loss-of-synchronism circle shapes of the unstable power swing region. A system separation angle of 120 degrees is used in accordance with PRC-026-1 – Attachment B criteria for each load-responsive protective relay evaluation.

Table 15 below is an example calculation of the apparent impedance locus method based on Figures 17 and 18.[28] In this example, the generator is connected to the 345 kV transmission system through the GSU transformer and has the listed ratings. Note that the load-responsive protective relays in this example may have ownership with the Generator Owner or the Transmission Owner.

---

[24] Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

[25] Ibid, Burdy.

[26] *Applied Protective Relaying*, Westinghouse Electric Corporation, 1979.

[27] Edward Wilson Kimbark, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

[28] Ibid, Kimbark.

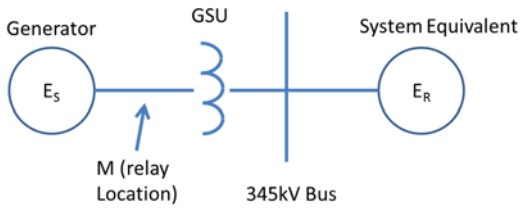


Figure 17: Simple one-line diagram of the system to be evaluated.

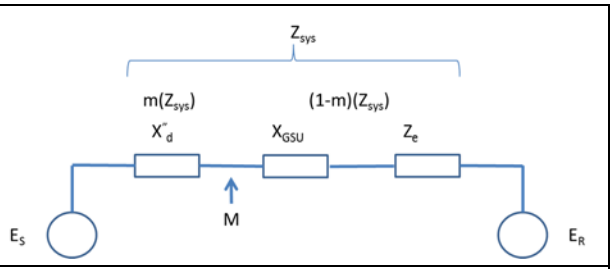


Figure 18: Simple system equivalent impedance diagram to be evaluated.[29]

Table15: Example Data (Generator)	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA)	940 MVA
Saturated transient reactance (940 MVA base)	$X'_d = 0.3845$ per unit
Generator rated voltage (Line-to-Line)	$20\ kV$
Generator step-up (GSU) transformer rating	$880\ MVA$
GSU transformer reactance (880 MVA base)	$X_{GSU} = 16.05\%$
System Equivalent (100 MVA base)	$Z_e = 0.00723\angle 90°$ per unit
Generator Owner Load-Responsive Protective Relays	
40-1	Positive Offset Impedance
	Offset = 0.294 per unit
	Diameter = 0.294 per unit
40-2	Negative Offset Impedance
	Offset = 0.22 per unit
	Diameter = 2.24 per unit
40-3	Negative Offset Impedance
	Offset = 0.22 per unit
	Diameter = 1.00 per unit
21-1	Diameter = 0.643 per unit
	MTA = 85°

[29] Ibid, Kimbark.

Table15: Example Data (Generator)	
50	I (pickup) = 5.0 per unit
Transmission Owned Load-Responsive Protective Relays	
21-2	Diameter = 0.55 per unit
	MTA = 85°

Calculations shown for a 120 degree angle and $E_S/E_R = 1$. The equation for calculating Z_R is:[30]

Eq. (106) $$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$$

Where m is the relay location as a function of the total impedance (real number less than 1)

E_S and E_R is the sending-end and receiving-end voltages

Z_{sys} is the total system impedance

Z_R is the complex impedance at the relay location and plotted on an R-X diagram

All of the above are constants (940 MVA base) while the angle δ is varied. Table 16 below contains calculations for a generator using the data listed in Table 15.

Table16: Example Calculations (Generator)			
The following calculations are on a 940 MVA base.			
Given:	$X'_d = j0.3845\ pu$	$X_{GSU} = j0.17144\ pu$	$Z_e = j0.06796\ pu$
Eq. (107)	$Z_{sys} = X'_d + X_{GSU} + Z_e$		
	$Z_{sys} = j0.3845\ pu + j0.17144\ pu + j0.06796\ pu$		
	$Z_{sys} = 0.6239\ \angle 90°\ pu$		
Eq. (108)	$m = \frac{X'_d}{Z_{sys}} = \frac{0.3845}{0.6239} = 0.6163$		
Eq. (109)	$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$		
	$Z_R = \left(\frac{(1-0.6163) \times (1\angle 120°) + (0.6163)(1\angle 0°)}{1\angle 120° - 1\angle 0°}\right) \times (0.6239\angle 90°)\ pu$		

[30] Ibid, Kimbark.

Table16: Example Calculations (Generator)	
	$Z_R = \left(\frac{0.4244 + j0.3323}{-1.5 + j\ 0.866}\right) \times (0.6239\angle 90°)\ pu$
	$Z_R = (0.3116 \angle -111.95°) \times (0.6239\angle 90°)\ pu$
	$Z_R = 0.194 \angle -21.95°\ pu$
	$Z_R = -0.18 - j0.073\ pu$

Table 17 lists the swing impedance values at other angles and at E_S/E_R = 1, 1.43, and 0.7. The impedance values are plotted on an R-X graph with the center being at the generator terminals for use in evaluating impedance relay settings.

Table 17: Sample Calculations for a Swing Impedance Chart for Varying Voltages at the Sending-End and Receiving-End.

	E_S/E_R=1		E_S/E_R=1.43		E_S/E_R=0.7	
	Z_R		Z_R		Z_R	
Angle (δ) (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)
90	0.320	-13.1	0.296	6.3	0.344	-31.5
120	0.194	-21.9	0.173	-0.4	0.227	-40.1
150	0.111	-41.0	0.082	-10.3	0.154	-58.4
210	0.111	-25.9	0.082	190.3	0.154	238.4
240	0.194	201.9	0.173	180.4	0.225	220.1
270	0.320	193.1	0.296	173.7	0.344	211.5

Requirement R2 Generator Examples

Distance Relay Application

Based on PRC-026-1 – Attachment B, Criterion A, the distance relay (21-1) (i.e., owned by the Generation Owner) characteristic is in the region where a stable power swing would not occur as shown in Figure 19. There is no further obligation to the owner in this standard for this load-responsive protective relay.

The distance relay (21-2) (i.e., owned by the Transmission Owner) is connected at the high-voltage side of the GSU transformer and its impedance characteristic is in the region where a stable power swing could occur causing the relay to operate. In this example, if the intentional time delay of this relay is less than 15 cycles, the PRC-026 – Attachment B, Criterion A cannot be met, thus the Transmission Owner is required to create a CAP (Requirement R3). Some of the options include,

but are not limited to, changing the relay setting (i.e., impedance reach, angle, time delay), modify the scheme (i.e., add PSB), or replace the Protection System. Note that the relay may be excluded from this standard if it has an intentional time delay equal to or greater than 15 cycles.

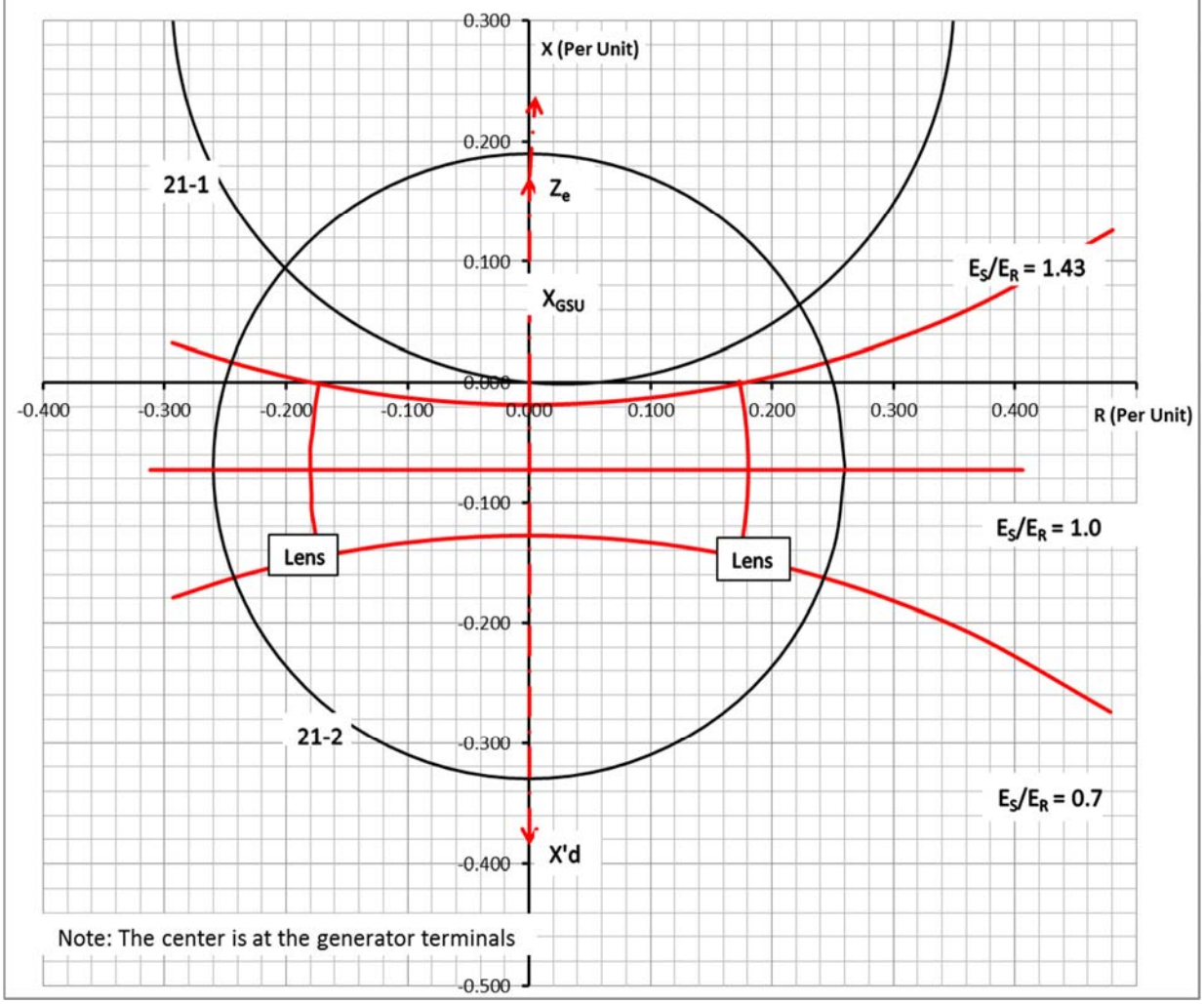


Figure 19: Swing impedance graph for impedance relays at a generating facility.

Loss-of-Field Relay Application

In Figure 20, the R-X diagram shows the loss-of-field relay (40-1 and 40-2) characteristics are in the region where a stable power swing can cause a relay operation. Protective relay 40-1 would be excluded if it has an intentional time delay equal to or greater than 15 cycles. Similarly, 40-2 would be excluded if its intentional time delay is equal to or greater than 15 cycles. For example, if 40-1 has a time delay of 1 second and 40-2 has a time delay of 0.25 seconds, they are excluded and there is no further obligation on the Generator Owner in this standard for these relays. The

loss-of-field relay characteristic 40-3 is entirely inside the unstable power swing region. In this case, the owner may select high speed tripping on operation of the 40-3 impedance element.

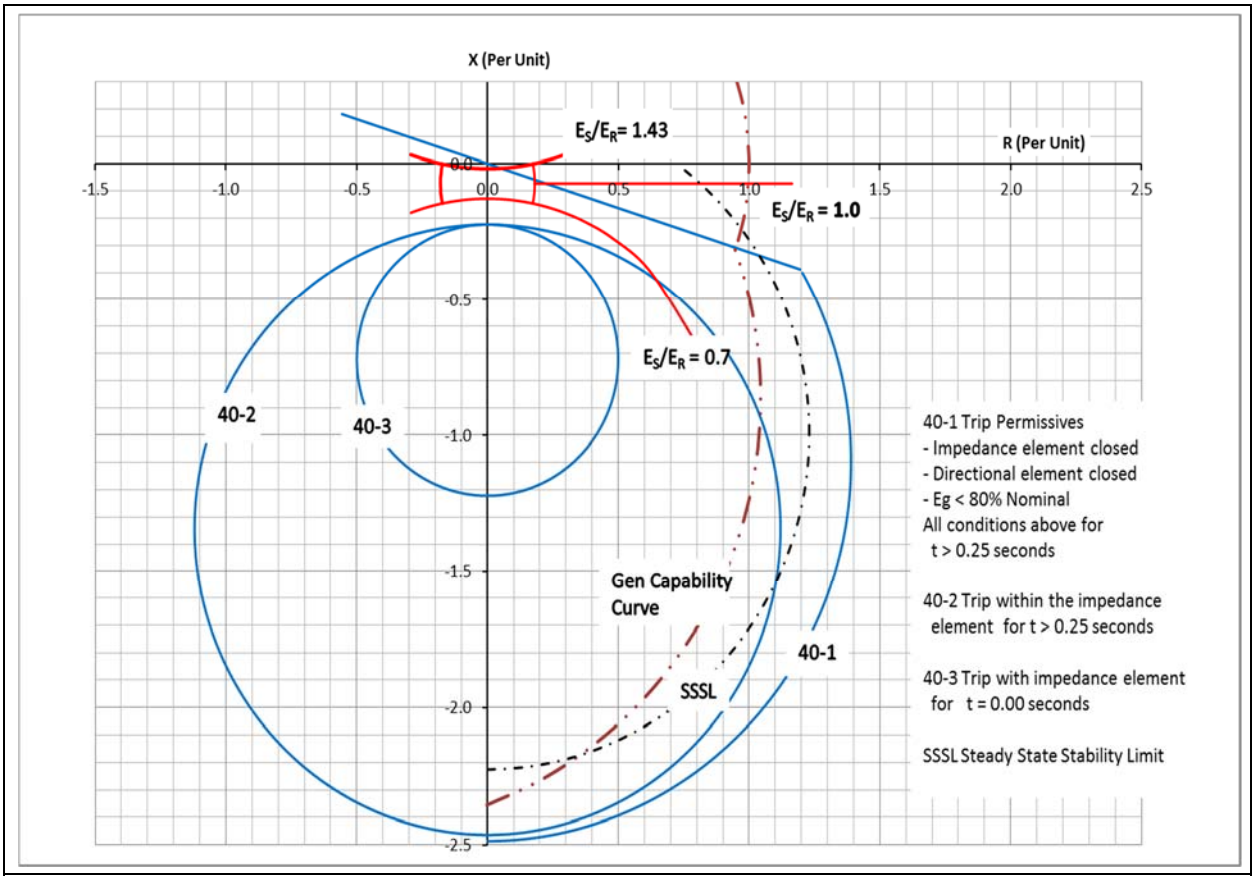


Figure 20: Typical R-X graph for loss-of-field relays with a portion of the unstable power swing region defined by PRC-026-1 – Attachment B, Criterion A.

Instantaneous Overcurrent Relay

In similar fashion to the transmission line overcurrent example calculation in Table 14, the instantaneous overcurrent relay minimum setting is established by PRC-026-1 – Attachment B, Criterion B. The solution is found by:

Eq. (110) $$I_{sys} = \frac{E_S - E_R}{Z_{\text{sys}}}$$

As stated in the relay settings in Table 15, the relay is installed on the high-voltage side of the GSU transformer with a pickup of 5.0 per unit. The maximum allowable current is calculated below.

$$I_{sys} = \frac{(1.05\angle 120° - 1.05\angle 0°)}{0.6239\angle 90°}\ pu$$

$$I_{sys} = \frac{1.819\angle 150°}{0.6239\angle 90°} pu$$

$$I_{sys} = 2.91\ \angle 60°\ pu$$

The instantaneous phase setting of 5.0 per unit is greater than the calculated system current of 2.91 per unit; therefore, it meets the PRC-026-1 – Attachment B, Criterion B.

Out-of-Step Tripping for Generation Facilities

Out-of-step protection for the generator generally falls into three different schemes. The first scheme is a distance relay connected at the high-voltage side of the GSU transformer with the directional element looking toward the generator. Because this relay setting may be the same setting used for generator backup protection (see Requirement R2 Generator Examples, Distance Relay Application), it is susceptible to tripping in response to stable power swings and would require modification. Because this scheme is susceptible to tripping in response to stable power swings and any modification to the mho circle will jeopardize the overall protection of the out-of-step protection of the generator, available technical literature does not recommend using this scheme specifically for generator out-of-step protection. The second and third out-of-step Protection System schemes are commonly referred to as single and double blinder schemes. These schemes are installed or enabled for out-of-step protection using a combination of blinders, a mho element, and timers. The combination of these protective relay functions provides out-of-step protection and discrimination logic for stable and unstable power swings. Single blinder schemes use logic that discriminate between stable and unstable power swings by issuing a trip command after the first slip cycle. Double blinder schemes are more complex than the single blinder scheme and, depending on the settings of the inner blinder, a trip for a stable power swing may occur. While the logic discriminates between stable and unstable power swings in either scheme, it is important that the trip initiating blinders be set at an angle greater than the stability limit of 120 degrees to remove the possibility of a trip for a stable power swing. Below is a discussion of the double blinder scheme.

Double Blinder Scheme

The double blinder scheme is a method for measuring the rate of change of positive sequence impedance for out-of-step swing detection. The scheme compares a timer setting to the actual elapsed time required by the impedance locus to pass between two impedance characteristics. In this case, the two impedance characteristics are simple blinders, each set to a specific resistive reach on the R-X plane. Typically, the two blinders on the left half plane are the mirror images of those on the right half plane. The scheme typically includes a mho characteristic which acts as a starting element, but is not a tripping element.

The scheme detects the blinder crossings and time delays as represented on the R-X plane as shown in Figure 21. The system impedance is composed of the generator transient (X_d'), GSU transformer (X_T), and transmission system (X_{system}), impedances.

The scheme logic is initiated when the swing locus crosses the outer Blinder R1 (Figure 21), on the right at separation angle α. The scheme only commits to take action when a swing crosses the

inner blinder. At this point the scheme logic seals in the out-of-step trip logic at separation angle β. Tripping actually asserts as the impedance locus leaves the scheme characteristic at separation angle δ.

The power swing may leave both inner and outer blinders in either direction, and tripping will assert. Therefore, the inner blinder must be set such that the separation angle β is large enough that the system cannot recover. This angle should be set at 120 degrees or more. Setting the angle greater than 120 degrees satisfies the PRC-026-1 – Attachment B, Criterion A (No. 1, 1st bullet) since the tripping function is asserted by the blinder element. Transient stability studies may indicate that a smaller stability limit angle is acceptable under PRC-026-1 – Attachment B, Criterion A (No. 1, 2nd bullet). In this respect, the double blinder scheme is similar to the double lens and triple lens schemes and many transmission application out-of-step schemes.

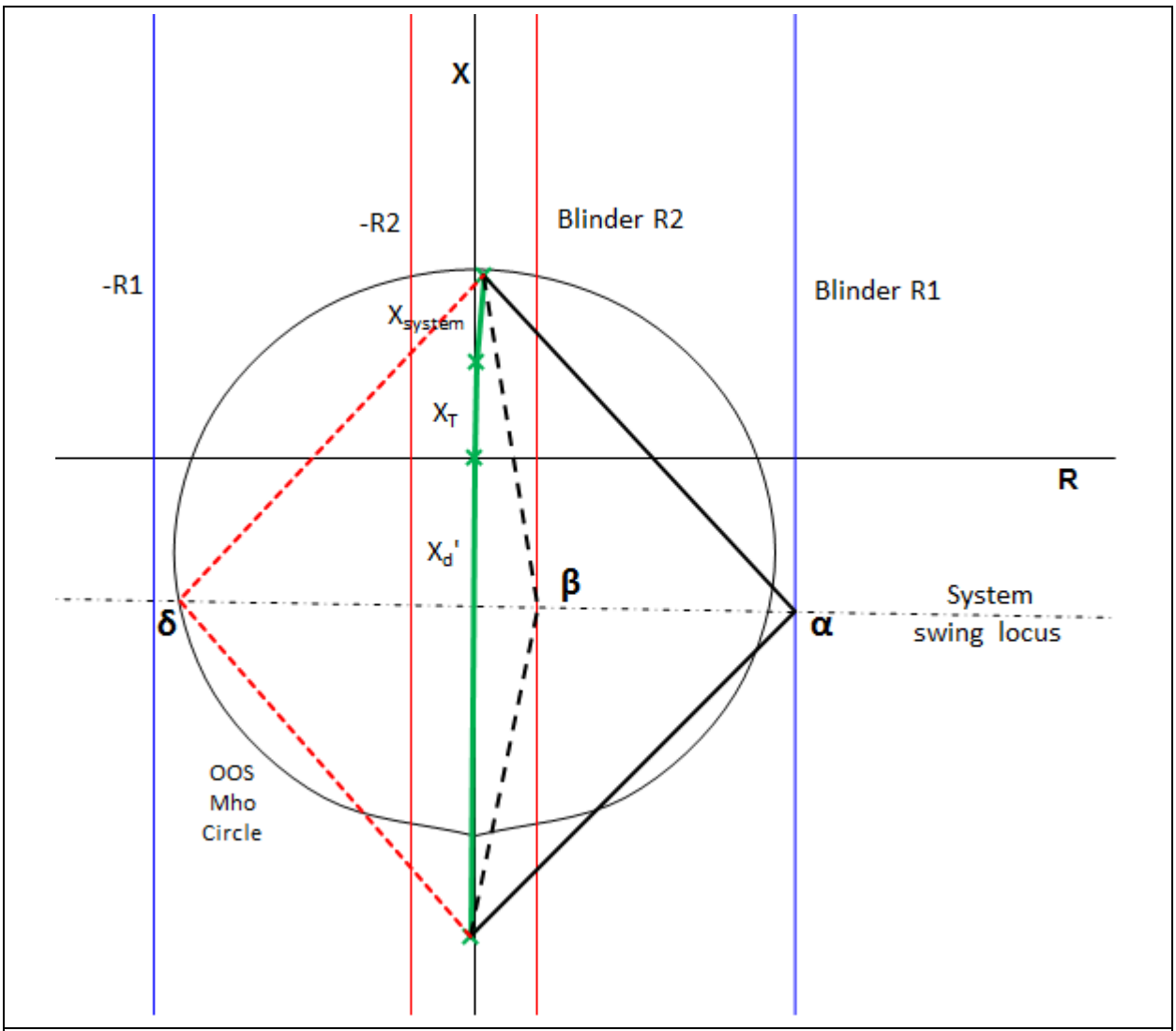


Figure 21: Double Blinder Scheme generic out of step characteristics.

Figure 22 illustrates a sample setting of the double blinder scheme for the example 940 MVA generator. The only setting requirement for this relay scheme is the right inner blinder, which must be set greater than the separation angle of 120 degrees (or a lesser angle based on a transient stability study) to ensure that the out-of-step protective function is expected to not trip in response to a stable power swing during non-Fault conditions. Other settings such as the mho characteristic, outer blinders, and timers are set according to transient stability studies and are not a part of this standard.

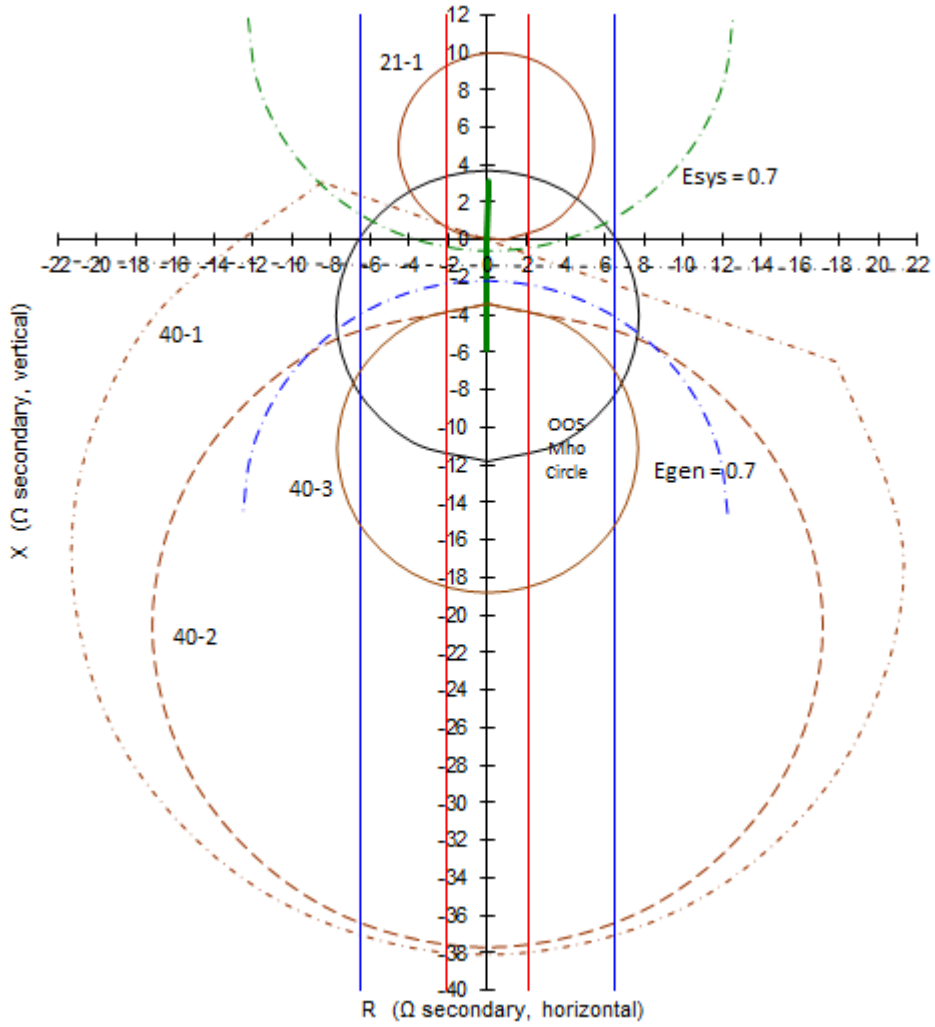


Figure 22: Double Blinder Out-of-Step Scheme with unit impedance data and load-responsive protective relay impedance characteristics for the example 940 MVA generator, scaled in relay secondary ohms.

Requirement R3

To achieve the stated purpose of this standard, which is to ensure that relays are expected to not trip in response to stable power swings during non-Fault conditions, this Requirement ensures that the applicable entity develops a Corrective Action Plan (CAP) that reduces the risk of relays tripping in response to a stable power swing during non-Fault conditions that may occur on any applicable BES Element.

Requirement R4

To achieve the stated purpose of this standard, which is to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions, the applicable entity is required to implement any CAP developed pursuant to Requirement R3 such that the Protection System will meet PRC-026-1 – Attachment B criteria or can be excluded under the PRC-026-1 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element). Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until all actions are complete. Accomplishing this objective is intended to reduce the occurrence of Protection System tripping during a stable power swing, thereby improving reliability and minimizing risk to the BES.

The following are examples of actions taken to complete CAPs for a relay that did not meet PRC-026-1 – Attachment B and could be at-risk of tripping in response to a stable power swing during non-Fault conditions. A Protection System change was determined to be acceptable (without diminishing the ability of the relay to protect for faults within its zone of protection).

> **Example R4a:** Actions: Settings were issued on 6/02/2015 to reduce the Zone 2 reach of the impedance relay used in the directional comparison unblocking (DCUB) scheme from 30 ohms to 25 ohms so that the relay characteristic is completely contained within the lens characteristic identified by the criterion. The settings were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.
>
> **Example R4b:** Actions: Settings were issued on 6/02/2015 to enable out-of-step blocking on the existing microprocessor-based relay to prevent tripping in response to stable power swings. The setting changes were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

The following is an example of actions taken to complete a CAP for a relay responding to a stable power swing that required the addition of an electromechanical power swing blocking relay.

> **Example R4c:** Actions: A project for the addition of an electromechanical power swing blocking relay to supervise the Zone 2 impedance relay was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The relay installation was completed on 9/25/2015. CAP was completed on 9/25/2015.

The following is an example of actions taken to complete a CAP with a timetable that required updating for the replacement of the relay.

> **Example R4d:** Actions: A project for the replacement of the impedance relays at both terminals of line X with line current differential relays was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The completion of the project was postponed due to line outage rescheduling from 11/15/2015 to 3/15/2016. Following the timetable change, the impedance relay replacement was completed on 3/18/2016. CAP was completed on 3/18/2016.

The CAP is complete when all the documented actions to remedy the specific problem (i.e., unnecessary tripping during stable power swings) are completed.

Justification for Including Unstable Power Swings in the Requirements

Protection Systems that are applicable to the Standard and must be secure for a stable power swing condition (i.e., meets PRC-026-1 – Attachment B criteria) are identified based on Elements that are susceptible to both stable and unstable power swings. This section provides an example of why Elements that trip in response to unstable power swings (in addition to stable power swings) are identified and that their load-responsive protective relays need to be evaluated under PRC-026-1 – Attachment B criteria.

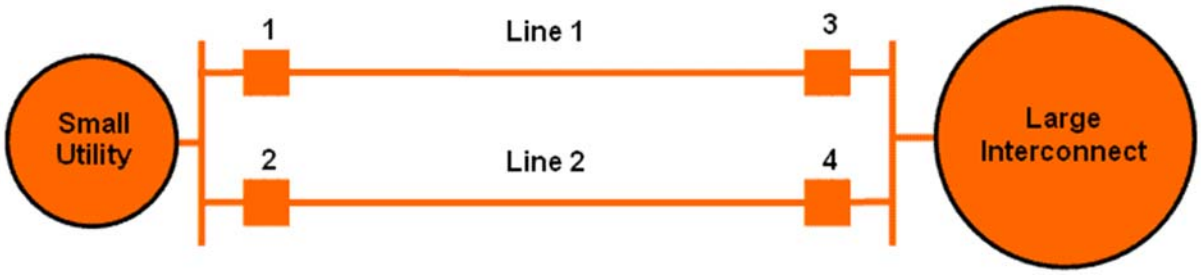


Figure 23: A simple electrical system where two lines tie a small utility to a much larger interconnection.

In Figure 23 the relays at circuit breakers 1, 2, 3, and 4 are equipped with a typical overreaching Zone 2 pilot system, using a Directional Comparison Blocking (DCB) scheme. Internal faults (or power swings) will result in instantaneous tripping of the Zone 2 relays if the measured fault or power swing impedance falls within the zone 2 operating characteristic. These lines will trip on

pilot Zone 2 for out-of-step conditions if the power swing impedance characteristic enters into Zone 2. All breakers are rated for out-of-phase switching.

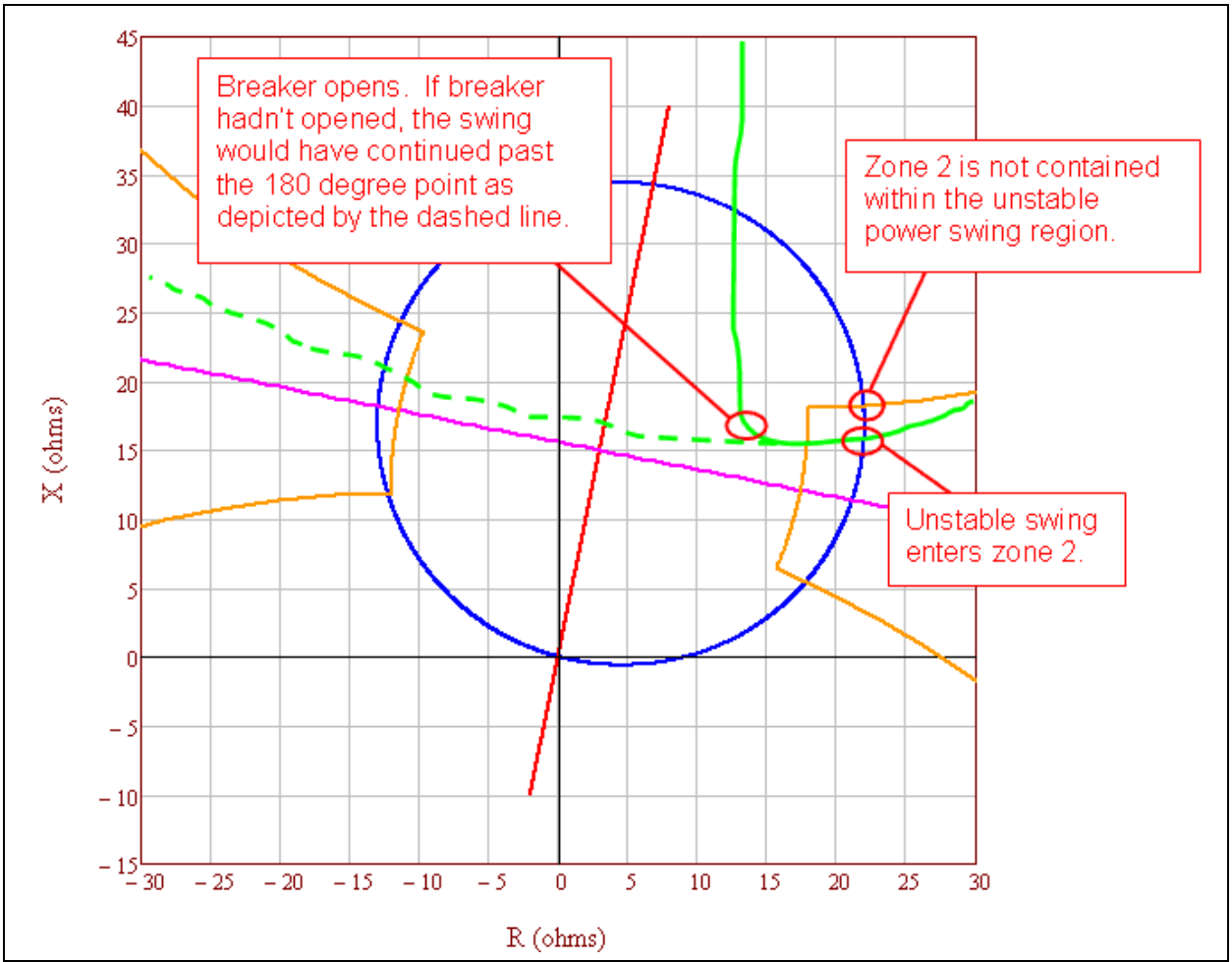


Figure 24: In this case, the Zone 2 element on circuit breakers 1, 2, 3, and 4 did not meet the PRC-026-1 – Attachment B criteria (this figure depicts the power swing as seen by relays on breakers 3 and 4).

In Figure 24, a large disturbance occurs within the small utility and its system goes out-of-step with the large interconnect. The small utility is importing power at the time of the disturbance. The actual power swing, as shown by the solid green line, enters the Zone 2 relay characteristic on the terminals of Lines 1, 2, 3, and 4 causing both lines to trip as shown in Figure 25.

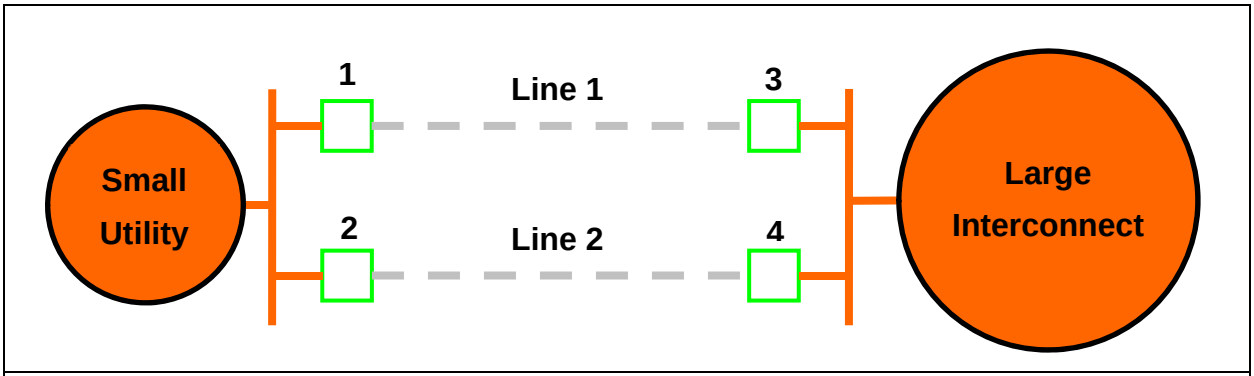


Figure 25: Islanding of the small utility due to Lines 1 and 2 tripping in response to an unstable power swing.

In Figure 25, the relays at circuit breakers 1, 2, 3, and 4 have correctly tripped due to the unstable power swing (shown by the dashed green line in Figure 24), de-energizing Lines 1 and 2, and creating an island between the small utility and the big interconnect. The small utility shed 500 MW of load on underfrequency and maintained a load to generation balance.

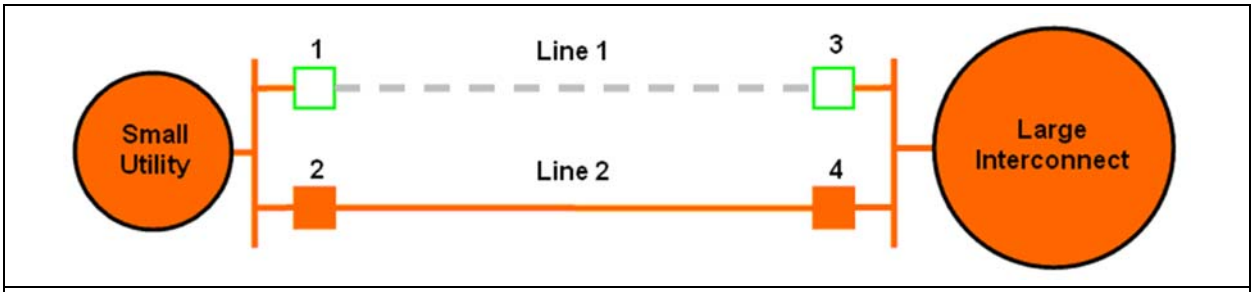


Figure 26: Line 1 is out-of-service for maintenance, Line 2 is loaded beyond its normal rating (but within its emergency rating).

Subsequent to the correct tripping of Lines 1 and 2 for the unstable power swing in Figure 25, another system disturbance occurs while the system is operating with Line 1 out-of-service for maintenance. The disturbance causes a stable power swing on Line 2, which challenges the relays at circuit breakers 2 and 4 as shown in Figure 27.

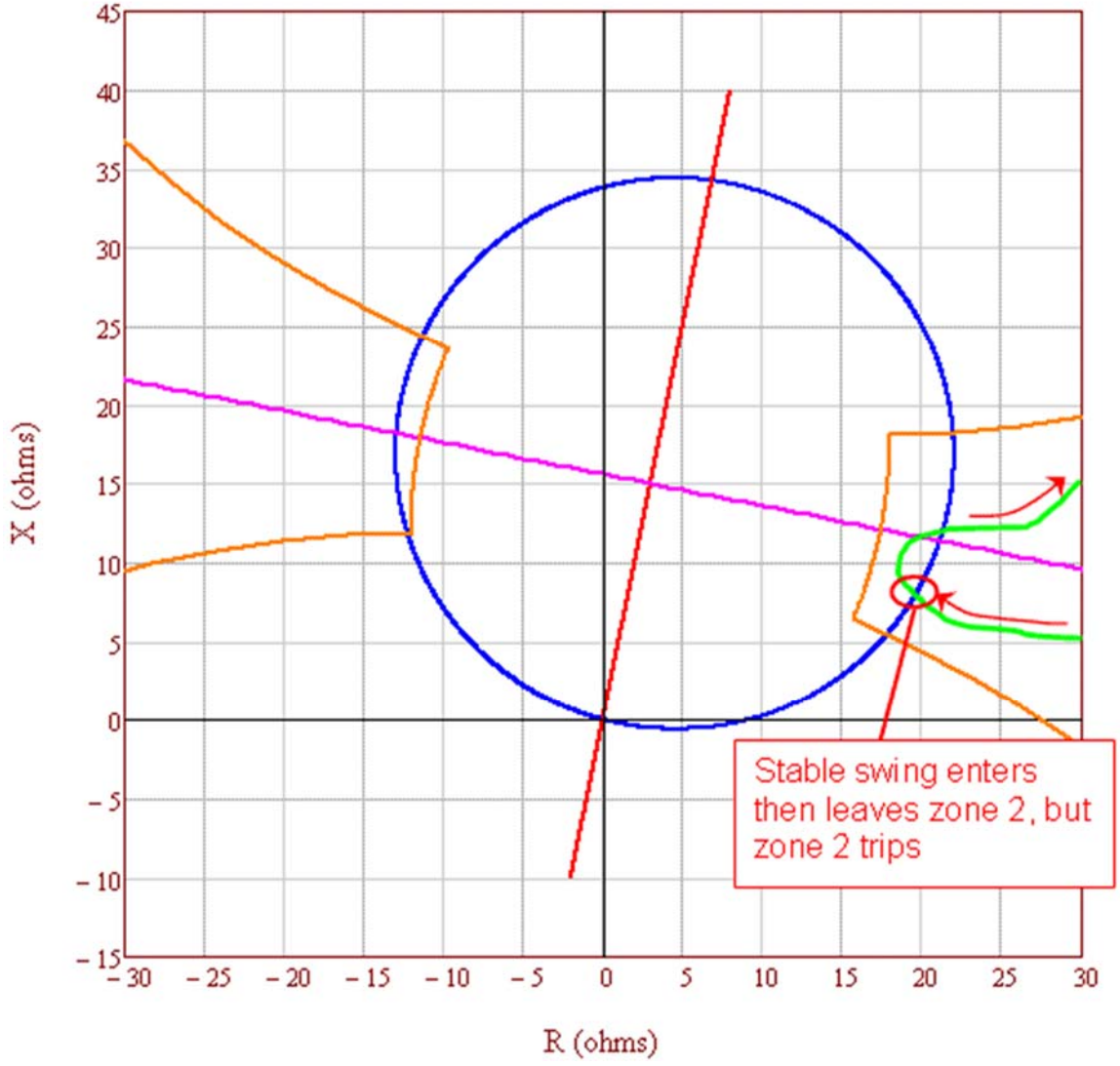


Figure 27: Relays on circuit breakers 2 and 4 were not addressed to meet the PRC-026-1 – Attachment B criteria following the previous unstable power swing event.

If the relays on circuit breakers 2 and 4 were not addressed under the Requirements for the previous unstable power swing condition, the relays would trip in response to the stable power swing, which would result in unnecessary system separation, load shedding, and possibly cascading or blackout.

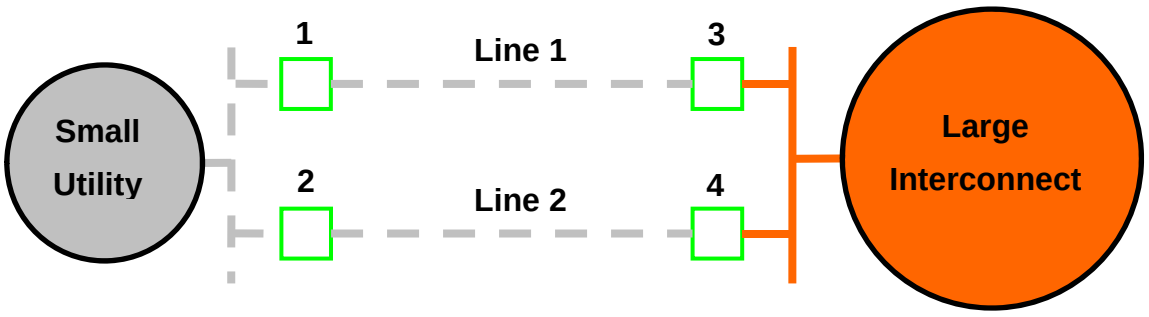


Figure 28: Possible blackout of the small utility.

If the relays that tripped in response to the previous unstable power swing condition in Figure 24 were addressed under the Requirements to meet PRC-026-1 - Attachment B criteria, the unnecessary tripping of the relays for the stable power swing shown in Figure 28 would have been averted, and the possible blackout of the small utility would have been avoided.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1

The Planning Coordinator has a wide-area view and is in the position to identify generator, transformer, and transmission line BES Elements which meet the criteria, if any. The criteria-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013 ("PSRPS Report"),[31] which recommends a focused approach to determine an at-risk BES Element. See the Guidelines and Technical Basis for a detailed discussion of the criteria.

Rationale for R2

The Generator Owner and Transmission Owner are in a position to determine whether their load-responsive protective relays meet the PRC-026-1 – Attachment B criteria. Generator, transformer, and transmission line BES Elements are identified by the Planning Coordinator in Requirement R1 and by the Generator Owner and Transmission Owner following an actual event where the Generator Owner and Transmission Owner became aware (i.e., through an event analysis or

[31] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Protection System review) tripping was due to a stable or unstable power swing. A period of 12 calendar months allows sufficient time for the entity to conduct the evaluation.

Rationale for R3

To meet the reliability purpose of the standard, a CAP is necessary to ensure the entity's Protection System meets the PRC-026-1 – Attachment B criteria (1st bullet) so that protective relays are expected to not trip in response to stable power swings. A CAP may also be developed to modify the Protection System for exclusion under PRC-026-1 – Attachment A (2nd bullet). Such an exclusion will allow the Protection System to be exempt from the Requirement for future events. The phrase, "…while maintaining dependable fault detection and dependable out-of-step tripping…" in Requirement R3 describes that the entity is to comply with this standard, while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Rationale for R4

Implementation of the CAP must accomplish all identified actions to be complete to achieve the desired reliability goal. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting CAP changes and completion of activities provides measurable progress and confirmation of completion.

Rationale for Attachment B (Criterion A)

The PRC-026-1 – Attachment B, Criterion A provides a basis for determining if the relays are expected to not trip for a stable power swing having a system separation angle of up to 120 degrees with the sending-end and receiving-end voltages varying from 0.7 to 1.0 per unit (See Guidelines and Technical Basis).

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Applicable Standard(s) and Definitions

- ~~Definition of System Voltage Limit (SVL) in the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")~~
  - FAC-011-4 System Operating Limits Methodology for the Operations Horizon
  - FAC-014-3 Establish and Communicate System Operating Limits
  - FAC-015-1 Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology
- CIP-014-3 Physical Security
- FAC-003-5 Transmission Vegetation Management
- FAC-013-3 Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- PRC-002-3 Disturbance Monitoring and Reporting Requirements
- PRC-023-5 Transmission Relay Loadability
- PRC-026-2 Relay Performance During Stable Power Swings
- Definition of System Voltage Limit in the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")
- Definition of System Operating Limit in the NERC Glossary

Requested Retirement(s)

- FAC-010-3 System Operating Limits Methodology for the Planning Horizon
- FAC-011-3 System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 Establish and Communicate System Operating Limits

~~[*New/Modified/Retired*] Terms in the NERC Glossary of Terms~~

~~**Proposed New Definition(s):**~~
~~System Voltage Limit: The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.~~

~~Applicable Entities~~

- ~~Reliability Coordinator~~
- ~~Planning Coordinator~~
- CIP-014-2 Physical Security
- FAC-003-4 Transmission ~~Planner~~Vegetation Management
- FAC-013-2 Assessment of Transfer Capability for the Near-term Transmission ~~Operator~~Planning Horizon
- PRC-002-2 Disturbance Monitoring and Reporting Requirements

- PRC-023-4 Transmission Relay Loadability
- PRC-026-1 Relay Performance During Stable Power Swings
- Currently-effective definition of System Operating Limit

Prerequisite Approvals

In addition to approval of the Reliability Standards included in this implementation plan, retirement of Reliability Standard FAC-010-3 cannot occur until the modifications in Reliability Standard CIP-002-6 (Cyber Security – BES Cyber System Categorization), Attachment 1, Criteria 2.6 and 2.9 become effective.

General Considerations

The elements of the Implementation Plans for PRC-002-2, PRC-023-4, and PRC-005-3 listed below shall remain applicable to PRC-002-3. PRC-023-5, and PRC-026-2and are incorporated herein by reference.

- Implementation of PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11:
  - Entities shall be at least 50 percent compliant within four (4) years of the effective date of PRC-002-2 and fully compliant within six (6) years of the effective date.
  - Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the effective date.
- Implementation of Newly Classified Remedial Action Schemes (RAS) (PRC-023-4)
  - Entities with newly classified “Remedial Action Scheme” (RAS) resulting from the application of the revised definition must be fully compliant with all Reliability Standards applicable RAS twenty-four (24) months from the Effective Date of the revised definition of RAS. This additional time applies only to existing schemes that must transition to RAS due to the revised definition. The additional time does not apply to future RAS that may be created following implementation of the revised definition.
- Implementation of PRC-026-1
  - Requirement R1: First day of the first full calendar year that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
  - Requirements R2, R3, and R4: First day of the first full calendar year that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year 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.

Effective Date

The effective date for proposed Reliability Standards FAC-011-4, FAC-014-3, ~~and~~ FAC-015-1~~ and~~, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the NERC Glossary ~~term~~terms "System Voltage Limit" and System Operating Limit" is provided below:

Where approval by an applicable governmental authority is required, Reliability Standards FAC-011-4, FAC-014-3, ~~and~~ FAC-015-1, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the NERC Glossary ~~term~~terms "System Voltage Limit" and "System Operating Limit" shall become effective the first day of the first calendar quarter that is twelve (12) calendar months after the effective date of the applicable governmental authority's order approving the standards and ~~term~~terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standards FAC-011-4, FAC-014-3, ~~and~~ FAC-015-1~~ and~~, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, the NERC Glossary ~~term~~terms "System Voltage Limit" and "System Operating Limit" shall become effective on the first day of the first calendar quarter that is twelve (12) calendar months after the date the standards and ~~term~~terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Currently-Effective NERC Reliability Standards

Reliability Standards FAC-010-3, FAC-011-3, ~~and FAC-014-2~~FAC-014-2, CIP-014-2, FAC-003-4, FAC-013-2, PRC-002-2, PRC-023-4, and PRC-026-1 shall be retired immediately prior to the effective date of the proposed Reliability Standards FAC-011-4, FAC-014-3, ~~and FAC-015.~~FAC-015, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the current definition of System Operating Limit.

Initial Performance of Periodic Requirements

FAC-014-3 Requirement R5, Parts 5.1 and 5.2

The initial performance of FAC-014-3, Requirement R5, Parts 5.1 and 5.2 must be within 12 calendar months of the effective date of FAC-014-3.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DRAFT

Cyber Security – BES Cyber System Logical Isolation

Technical Rationale and Justification for Reliability Standard CIP-005-7

RELIABILITY | ACCOUNTABILITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Table of Contents

Introduction ..... **iv**

Executive Summary **5**

New and Modified Terms Used in NERC Reliability Standards **7**

Proposed Modified Terms: 7

BES Cyber Asset (BCA) 7

External Routable Connectivity (ERC) 7

Interactive Remote Access (IRA) 7

Intermediate Systems (IS) 7

Physical Access Control Systems (PACS) 8

Physical Security Perimeter (PSP) 8

Protected Cyber Asset (PCA) 8

Removable Media 9

Transient Cyber Asset (TCA) 9

Proposed New Terms: 9

Electronic Access Control Systems (EACS) 9

Electronic Access Monitoring System (EAMS) 10

Electronic Security Zone (ESZ) 10

Physical Access Monitoring System (PAMS) 10

Shared Cyber Infrastructure (SCI) 11

Virtual Cyber Asset (VCA) 12

Proposed Retired Terms: 12

EACMS 13

EAP 13

General Considerations **14**

Logical Isolation 14

Shared infrastructure and “Mixed Trust” Risks 14

Hybrid Virtual/Physical Scenarios with ESP/ESZ’s 15

EACMS/PACS Glossary Terms 19

External Routable Connectivity (ERC) and Interactive Remote Access (IRA) 19

Assets with Multiple Classifications (PCA, EACS, IS, SCI, etc.) 21

Requirement R1 ..... **22**

General Considerations for Requirement R1 22

Requirement R2 ..... **33**
Appendix 1 – ESZ's **38**
Appendix 2 - Technical Rational for Reliability Standard CIP-005-6 ..... **41**
Section 4 – Scope of Applicability of the CIP Cyber Security Standards 41
Requirement R1: 41
Requirement R2: 43

Introduction

This document is the technical rationale and justification for the proposed Reliability Standard CIP-005-7. The Standard Drafting Team's (SDT) intent of this document is to provide stakeholders and the ERO Enterprise with an understanding of the proposed revisions and the technical concepts of the Reliability Standard. This Technical Rationale and Justification for CIP-005-7 is not a Reliability Standard and should not be considered mandatory and enforceable.

Executive Summary

This document explains the technical rationale and justification for the proposed Reliability Standard CIP-005-7. The Standard Drafting Team (SDT) is proposing changes to CIP-005-6 as it updates the standards based on technology innovation and changes such as the increasing use of virtualization. Project 2016-02 SDT was assigned the task to address the technological innovation in virtualization within the CIP standards. The SDT's purpose of incorporating the virtualization concept into the CIP standards is not to merely augment the current standards. The SDT's intent is to better position the CIP standards to be applicable to additional future technological innovation.

The Project 2016-02 CIP SDT proposes the following modified terms within the NERC Glossary:

- BES Cyber Asset (BCA);
- External Routable Connectivity (ERC);
- Interactive Remote Access (IRA);
- Intermediate System (IS);
- Physical Access Control System (PACS);
- Physical Security Perimeter (PSP);
- Protected Cyber Asset (PCA);
- Removable Media (RM); and
- Transient Cyber Asset (TCA).

The Project 2016-02 CIP SDT proposes the following new terms to the NERC Glossary:

- Electronic Access Control Systems (EACS);
- Electronic Access Monitoring System (EAMS);
- Electronic Security Zone (ESZ);
- Physical Access Monitoring System (PAMS);
- Shared Cyber Infrastructure (SCI); and
- Virtual Cyber Asset (VCA).

The Project 2016-02 CIP SDT proposes to retire the following terms:

- Electronic Access Control and Monitoring System (EACMS); and
- Electronic Access Point (EAP).

These modified terms, new terms, and retired terms are further explained herein.

The title and purpose of CIP-005-7 changed from Electronic Security Perimeters to Logical Isolation. ESP's and EAPs remain a valid option and are one method for implementing logical isolation. However, virtualized technologies present other equally effective methods than ESPs that deal only with layer 3 routable protocol addressing. To adapt virtualization's characteristics, CIP-005-7 focuses on logical isolation such that high and medium impact BES Cyber Systems be "logically isolated" from all other systems (regardless of protocol) to replace the routable protocol-based ESP requirement as the solitary method that may be used.

Another concept introduced within CIP-005-7 is shared infrastructure. For virtualized environments where shared infrastructure (hardware) is used, a risk of side channel attacks exists. CIP-005-7 proposes to require the placing of virtualized systems of differing trust levels into differing ESZ's, and then affinity controls must be applied to these zones. These affinity groups must be configured such that a hypervisor does not allow workloads in these differing zones to simultaneously exist or execute on the same hardware underlay compute resources.

Additionally, the SDT is proposing a new requirement (CIP-005-7 R1.6) to separate the management plane of the SCI from the data plane. This is needed to ensure the reliability and security of the management plane.

CIP-005-7 also introduces exemptions and requirements for extending ESPs or ESZs across geographic locations also known as "Super ESPs". This allows, for example, entities to extend a network to replicate data at high speed between two virtualization infrastructures (SCI) or two databases in two different geographic locations to improve the resilience and reliability of BES Cyber Systems. Requirement 1 Part 1.3 within CIP-005-7 requires that data traversing "Super ESPs" be protected to preserve its integrity and confidentiality.

New and Modified Terms Used in NERC Reliability Standards

Proposed Modified Terms:

BES Cyber Asset (BCA)

A Cyber Asset or Virtual Cyber Asset; excluding Shared Cyber Infrastructure, that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.

Rationale

The BCA definition is changing to allow for BES Cyber Assets to be either Cyber Assets (hardware included) or Virtual Cyber Assets (without the underlying hardware). The definition of BCA excludes the underlying hardware for virtualized environments, now defined as Shared Cyber Infrastructure (SCI). The SDT recognizes that SCI indeed has the same impact as a virtual BES Cyber Asset and even more so if hosting numerous BES Cyber Assets. For the first formal posting of all affected standards, the requirements for SCI will be equal to BCA and in fact be subjected to additional requirements due to its impact (e.g. CIP-005 R1 Part 1.6). See the SCI definition below.

External Routable Connectivity (ERC)

The ability to access a BES Cyber System from a Cyber Asset or Virtual Cyber Asset that is outside of its associated Electronic Security Perimeter or Electronic Security Zone via a bi-directional routable protocol connection.

Rationale

The ERC definition is used throughout the CIP Standards, within the Applicable Systems column, as a scoping mechanism based on the inherent risk associated with external routable connectivity. In order to maintain the correct ERC scoping the SDT made conforming changes to the ERC definition to include both Virtual Cyber Assets and ESZs, but maintained the caveat of "via a routable protocol connection." This effectively updates the ERC term to include the applicable new concepts presented within the updated CIP Standards.

Interactive Remote Access (IRA)

User-initiated access by a person employing a remote access client.

Rationale

The IRA definition is changing to remove several requirements and scoping mechanisms that were embedded within it so that it becomes a simple glossary definition. The requirements and scoping mechanisms have been moved into CIP-005 R2. The references to ownership of the remote client have been removed as immaterial to the definition or the CIP-005 requirements. The reliance on "using a routable protocol" has been removed to incorporate IP to serial conversion scenarios to serial only Cyber Assets. See discussion under the General Considerations section below.

Intermediate Systems (IS)

A type of EACS that is used to restrict Interactive Remote Access.

Rationale

The IS definition is changing to remove requirements-like language (e.g. where an IS must reside) that was embedded within the definition. Such language has been moved to CIP-005 R2.

Physical Access Control Systems (PACS)

Cyber Assets or Virtual Cyber Assets that control access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.

Rationale

The PACS definition is changing to 1) allow Virtual Cyber Assets as a form that PACS can take, and 2) separate out the non-access control functions (see PAMS below). This will allow differentiation in requirements based on the different risk profiles of a system that controls physical access versus systems that only log or alert (i.e. a SIEM or internal or outsourced monitoring service). The intent is that a system that both controls and monitors physical access remains a PACS. If the system controls physical access, it is a PACS regardless of its monitoring capabilities.

Physical Security Perimeter (PSP)

The physical border at which access is controlled.

Rationale

The PSP definition is changing to remove references to EACMS and other applicable systems. The applicability of the CIP-006 PSP requirements was included within the definition, so as the applicability of the requirements change over time (such as adding SCI), the definition would need to change. The SDT is proposing to remove not only the proposed retired term EACMS but all applicability from the definition to avoid current and future issues.

Protected Cyber Asset (PCA)

Cyber Assets or Virtual Cyber Assets that:

- Are connected using a routable protocol within or on an Electronic Security Perimeter that are not part of the highest impact BES Cyber System within the same Electronic Security Perimeter; or
- Are within the same Electronic Security Zone that are not part of the highest impact BES Cyber System within the same Electronic Security Zone; or
- Share compute resources (CPU or memory) with a BES Cyber System.

Rationale

The PCA definition is being updated to include the ESZ option so that Cyber Assets within an ESZ that are not part of the highest impact BES Cyber System within the zone become an associated PCA of the highest impact BES Cyber System.

The definition is also being updated to include “share compute resources (CPU or memory) with a BES Cyber System” to mitigate the risks of hardware-based vulnerabilities (Spectre, Meltdown, Rowhammer, etc.) on Shared Cyber Infrastructure. Since virtualization can allow systems of differing trust levels to simultaneously execute on the same hypervisor servers in the hardware underlay and thus share the same CPU and memory, this addition to the PCA definition requires that those VCAs that do share CPU and memory become associated PCA’s of any BES Cyber Systems sharing the same hypervisor compute resources. This provides the high water marking of VCAs sharing a single hypervisor’s CPU or memory.

See the “Shared Infrastructure and ‘Mixed Trust’ Risks” section below for a more in-depth discussion.

Removable Media

Storage media that (i) are not Cyber Assets, (ii) are capable of transferring executable code, (iii) can be used to store, copy, move, or access data, and (iv) are directly connected for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP or ESZ, a Protected Cyber Asset, or SCI.

Rationale

The Removable Media definition has conforming changes to allow the targets to which the media may be connected include SCI and a network within an ESZ.

Transient Cyber Asset (TCA)

A Cyber Asset or Virtual Cyber Asset that is:

1. capable of transmitting or transferring executable code,
2. not included in a BES Cyber System,
3. not a Protected Cyber Asset (PCA) associated with high or medium impact BES Cyber Systems, and
4. directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless including near field or Bluetooth communication) for 30 consecutive calendar days or less to a:
    - BES Cyber Asset,
    - Shared Cyber Infrastructure (SCI),
    - network within an Electronic Security Perimeter (ESP) or Electronic Security Zone (ESZ) containing high or medium impact BES Cyber Systems, or
    - PCA associated with high or medium impact BES Cyber Systems.

Examples of Transient Cyber Assets include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.

Rationale

The TCA definition is changing to incorporate the virtualization definitions in three ways. First, VCA is being added as a form a TCA can take. The intent is to handle VCAs that are created for typical TCA uses but are normally dormant (e.g. a Virtual Machine (VM) with Wireshark for troubleshooting network issues within a virtualized infrastructure). Secondly, SCI was added as a target to which TCA's can be directly connected. Thirdly, conforming changes were made to add connection to a network within an ESZ as an option.

Proposed New Terms:

Electronic Access Control Systems (EACS)

Cyber Assets or Virtual Cyber Assets that provide electronic access control to an ESP, ESZ, or BES Cyber Systems.

Rationale

The EACMS definition is splitting into two terms. The EACS definition is proposed to 1) allow Virtual Cyber Assets as a form that EACS can take, and 2) separate out the non-access control functions. This will allow differentiation in requirements based on the different risk profiles of a system that controls access (i.e. a firewall) versus systems that only log or alert (i.e. a SIEM or internal or outsourced monitoring service). The intent is that a system that both controls and monitors electronic access remains an EACS. If the system controls electronic access, it is an EACS regardless of its monitoring capabilities.

Electronic Access Monitoring System (EAMS)

Cyber Assets or Virtual Cyber Assets that provide electronic access monitoring of an ESP, ESZ, or BES Cyber Systems.

Rationale

The EACMS definition is splitting into two terms. The EAMS definition is proposed to 1) allow Virtual Cyber Assets as a form that EAMS can take, 2) incorporate ESZs, and 3) separate out the non-access control functions. This will allow differentiation in requirements based on the different risk profiles of a system that controls access (i.e. a firewall) versus systems that only log or alert (i.e. a SIEM or internal or outsourced monitoring service).

Electronic Security Zone (ESZ)

A segmented section of a network that contains systems and components to create logical isolation.

Rationale

In previous versions of the CIP standards, CIP-005 required declarations of Electronic Security Perimeters (ESP) based on OSI layer 3 routable protocols. All BES Cyber Assets (BCA) that were connected to a network with routable protocols had to reside inside a declared ESP. Any External Routable Connectivity (ERC) to the BES Cyber Systems inside the ESP had to enter and exit via an Electronic Access Point (EAP) that limited the traffic entering or leaving the ESP to only necessary traffic. It denied all other traffic by default.

This "castle and moat with drawbridge" protection, where the castle is the BES Cyber Systems (BCS), the moat is the ESP, and the drawbridge is the EAP, has been in place for many years. For many situations, the ESP/EAP model remains a valid network architecture however it is no longer the only model. Prescribing the ESP/EAP as the sole model hinders the adoption of other models that are equally or even more effective. Network access control is expanding beyond perimeter-based security at routable protocol address levels into other models where access controls are enforced within the network fabric itself. The entire network is becoming "the firewall" rather than a centralized point at a network boundary. Within virtualized environments, entities can describe network access at a policy level within a *zone* and zones may not follow the typical IP subnet defined network space. Zones allow for network access permissions to be applied to workloads based on their function and/or trust level rather than purely by network location which for resiliency purposes can be very dynamic. If a virtual machine is a member of a zone, it gets that zone's access permissions applied to it regardless of its network location. IP addresses and port numbers, which are simply protocol data, become less common methods of identifying and filtering communications, especially in virtual environments where workloads dynamically move and may change network location but stay within the same zone. The zone's policies follow the workload, not a network address range. This is driving solutions more towards policy-based user access controls for workloads that the infrastructure then dynamically applies within the environment.

In essence, as network access controls become embedded into the infrastructure, these environments may no longer have an "Electronic Access *POINT*"; no single interface on a perimeter where network access rules are enforced but are instead highly distributed within the network. This is the reason the CIP standards are adding the "Electronic Security Zone" (ESZ) concept as an option that can be chosen for systems in addition to or in place of the ESP/EAP model.

Physical Access Monitoring System (PAMS)

Cyber Assets or Virtual Cyber Assets that alert or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.

Rationale

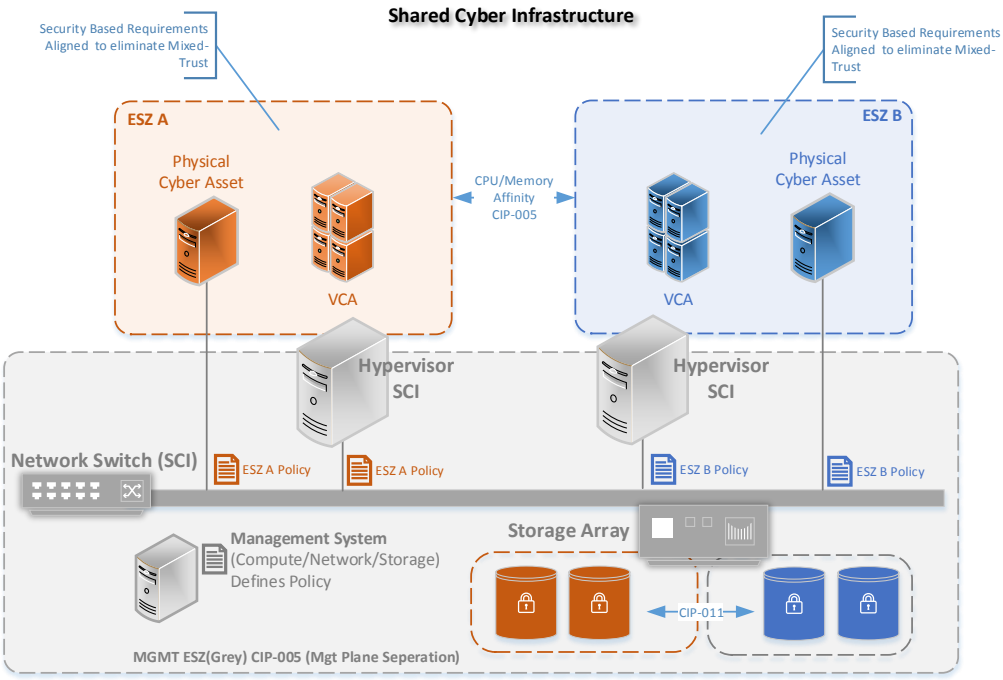
The PACS definition is splitting into two terms. The PAMS definition is proposed to 1) allow Virtual Cyber Assets as a form that PAMS can take, and 2) separate out the non-access control functions. This will allow differentiation in requirements based on the different risk profiles of a system that controls access (i.e. a badging system) versus systems that only log or alert (i.e. a SIEM or internal or outsourced monitoring service that only receives data).

Shared Cyber Infrastructure (SCI)

Programmable electronic devices whose compute, storage (including network transport), or network resources are shared with one or more Virtual Cyber Assets or that perform logical isolation for an ESZ or ESP. This includes its management systems.

Rationale

The SCI definition is being created to separate the underlying hardware from the VCAs that it hosts. This allows security requirements to be targeted to SCI to address the unique risks of virtualization and shared hardware. There are many requirements that now include the newly defined term SCI in the "Applicable Systems" column to maintain security level parity with traditional Cyber Assets. This change is justified because the hardware underlay would not have required protections at the same level as an applicable virtual system without this inclusion.



Beyond security level parity with protecting a typical hardware based Cyber Asset, the SCI can have a more significant impact in a virtualized environment since it can host, and therefore impact, multiple virtualized systems. Because of this capability, some additional controls only apply to SCI, such as the management plane isolation required by the proposed CIP-005-6 R1.6.

The statement "or performs logical isolation for an ESZ or ESP" is found within the Shared Cyber Infrastructure definition. This inclusion is intended to ensure that devices that provide logical isolation for an ESZ or ESP, and therefore have an associated risk, have protection for the associated management systems (management plane) as required by Part 1.6. This inclusion is meant to ensure protection of firewalls or network switches if used to provide logical isolation to an ESP, ESZ, or within Shared Cyber Infrastructure (see discussion and examples under the R1.6 section below). This can be viewed as a replacement for the Electronic Access Point (EAP) found in the previous version of the standard.

In the diagram above, an orange ESZ and a blue ESZ are depicted. Each ESZ contains VCAs and a physical Cyber Asset along with storage configured within a storage array. The individual ESZs are defined via policies created in the management system that are implemented by the SCI to create the logical isolation of that zone within the SCI's compute, network, and storage resources. The SCI for this scenario is depicted in grey and includes the hypervisor servers, the network switch, the storage array hardware, and the management system(s) for each.

Virtual Cyber Asset (VCA)

A logical instance of an operating system, firmware, or self-contained application hosted on SCI.

Rationale

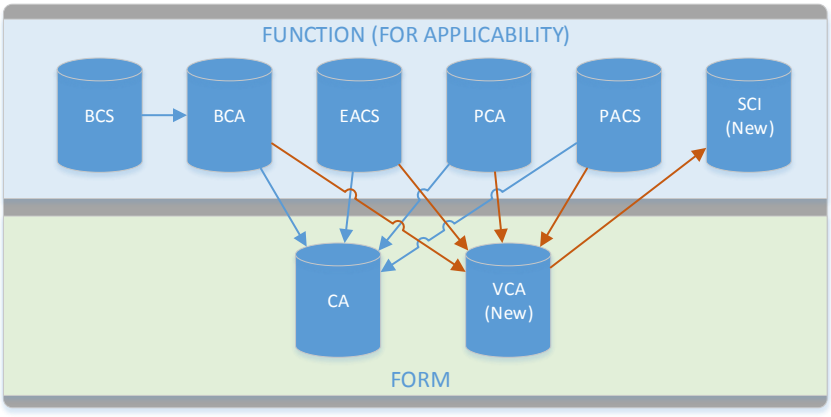
The NERC Glossary definition of Cyber Asset has a direct tie to the hardware on which it relied. This affected the definitions of the "Applicable Systems" terms such as BES Cyber Systems (BCS), EACS, PACS, and Protected Cyber Assets (PCAs). Because the Reliability Standard is applicable to the aforementioned systems, the control for the Cyber Assets also applies to the hardware. This tie to hardware implies a singular one BCA, EACS, PACS or PCA per individual hardware system. This one-to-one relationship between a Virtual Cyber Asset and its underlying hardware is what virtualization intentionally breaks to increase reliability and resiliency by allowing Virtual Cyber Assets to be abstracted from a particular hardware cyber asset and therefore able move to any available hardware out of a pool of resources.

The proposed NERC Glossary definition of Virtual Cyber Asset (VCA) allows the tie between a specific piece of hardware and the related applicable systems to no longer be singularly defined. The definition of VCA is not inclusive of hardware, and the EACS, PACS and PCA definitions have been updated to allow for VCA versions. With the addition of SCI and revisions to the "Applicable Systems", there can be one or more virtualized instances of a BCA, EACS, PACS or PCA that reside on SCI.

Examples of Virtual Cyber Assets may include, but are not limited to, logical instances of the following:

- Operating Systems (Virtual Machines (VM));
- Containers, which are executable software package images that are standalone and self-contained;
- Networking devices such as switches, routers, and load balancers;
- Security appliances such as firewalls and VPN concentrators; and
- Helper appliances with logical connectivity (such as malware detection, plugins, etc.).

This diagram depicts the relationship between many of the glossary definitions in that some are the "form" of an object and some are the "function" it provides. The top row shows definitions of "functions" or services that are performed or provided. The bottom row is the "form". Previously the only form that existed was the Cyber Asset definition which included the hardware and historically had a 1:1 relationship (e.g. a digital relay, a desktop computer operator workstation, a database server in a rack, etc.). The addition of the Virtual Cyber Asset definition clarifies a new form that the functions can take which is abstracted from the underlying hardware. The new SCI definition provides the functions of compute, network, and storage resources and logical isolation for VCAs. The blue arrows are the existing definitional relationships and the red arrows are the new definitional relationships that are being added.



Proposed Retired Terms:

EACMS

Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Systems.

Rationale

The EACMS definition is splitting into two terms (EACS and EAMS) to allow differentiation in requirements based on the different risk profiles of a system that controls access (i.e. a firewall) versus systems that only log or alert (i.e. a SIEM or internal or outsourced monitoring service). The combined term is proposed to be retired.

EAP

A Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.

Rationale

With the move to an objective based requirement in CIP-005 and the need to not prescribe a cyber asset interface, an electronic access POINT, on a network boundary as the only model for addressing network access control, the term EAP is no longer used within the standard and is proposed to be retired. Entities are free to continue to use the term in their internal documentation to maintain backwards compatibility. See also the discussion for the SCI and ESZ definitions.

Logical Isolation

The title and purpose of CIP-005-7 changed from Electronic Security Perimeters to Logical Isolation. ESP's and EAPs remain a valid option and are one method for implementing logical isolation. However, virtualization technologies present other equally effective methods than ESPs that deal only with layer 3 routable protocol addressing. Virtualization and its accompanying shared infrastructure have other characteristics such as shared computing hosts, shared storage, shared virtual networks and switches, all of which pose different security concerns but also have different security controls. To adapt to these changes, CIP-005-7 focuses on an objective-based requirement (in Requirement Part 1.2) for logical isolation.

The SDT chose the term "logical isolation" to distinguish the type of isolation required from complete isolation or physical isolation alone. Logical isolation refers to the isolation of communications between systems. Two BES Cyber Systems can be physically isolated into two different access-controlled areas, but still have uncontrolled communication between them. Also, two virtual cyber systems within two different ESZs or ESPs of differing trust or impact levels may be running on two hypervisors within the same physical area, but still be logically isolated from each other. *Logical isolation means that only known, controlled communications can occur between a system and anything outside of its ESZ or ESP and that all other communication is blocked.* Serial communications such as RS-232 or RS-485 are logically isolated communications methods as well. These types of communications move data from the TX pin on one end of a cable to the RX pin on the other end of the cable. There is no addressing scheme or routing/firewall capability, so it meets the intent of logical isolation.

If a BCS is executing on a virtual host along with another related virtual machine that may not have a 15-minute impact, (e.g. a control system and its data historian), the entity must either consider all these workloads as part of a single system or declare the system with the 15-minute impact as a BCS and the historian as a separate system. If the latter is chosen, the entity will need to prove that the two systems are logically isolated and that every communication between the two is limited to only what is necessary.

Logical isolation is also relevant to other layers of a computing stack. Imagine in a virtualized data center where you are looking at a BES Cyber System architecture "from the side". You can see the different layers of the system, from the storage on a Storage Area Network (SAN) through the virtual networks, switches, and firewalls at the virtual network layer, up to the virtual hosts that are executing the application workloads. If you rotate the view until you are looking down at the system from above, you should be able to see the touch points of all these layers to other systems. Logical isolation refers to this top-down view. An entity needs to be able to show that only necessary data flows are allowed through any of these layers that have an interface to another system. For example, at a storage layer, BCS systems should have their storage logically isolated from other systems that are not part of the BCS. At a networking layer, there should be no communications channels that allow the BCS to talk to any other system that is not controlled. At a virtual machine level, there should be logical isolation between VMs. As you "look down" through the computing stack, you should only see interface points that are controlled and locked down to a least-privilege position. To allow for implementation of this isolation, the ESZ concept has been introduced so that systems of the same trust level can be placed into their own ESZ and the controls placed on the zone.

Shared infrastructure and "Mixed Trust" Risks

For virtualized environments where shared infrastructure (hardware) is used, a risk of side channel attacks exists. Virtualization allows disparate workloads of what could be differing impact or trust levels to execute on the same CPUs and share the same RAM within the infrastructure. There are vulnerabilities that are directly related to sharing hardware such as Spectre, Meltdown, and Rowhammer. Rowhammer for example concerns processes sharing

certain forms of hardware memory such as DRAM. Repeated writing of bits in one process could flip bits in a process in adjacent physical memory. This type of vulnerability is one of the unique risks of Shared Cyber Infrastructure.

As this class of vulnerability is specifically about processes executing side by side on the same CPU or memory chips in a SCI environment, the risk of these vulnerabilities is being mitigated in CIP-005-7 by either:

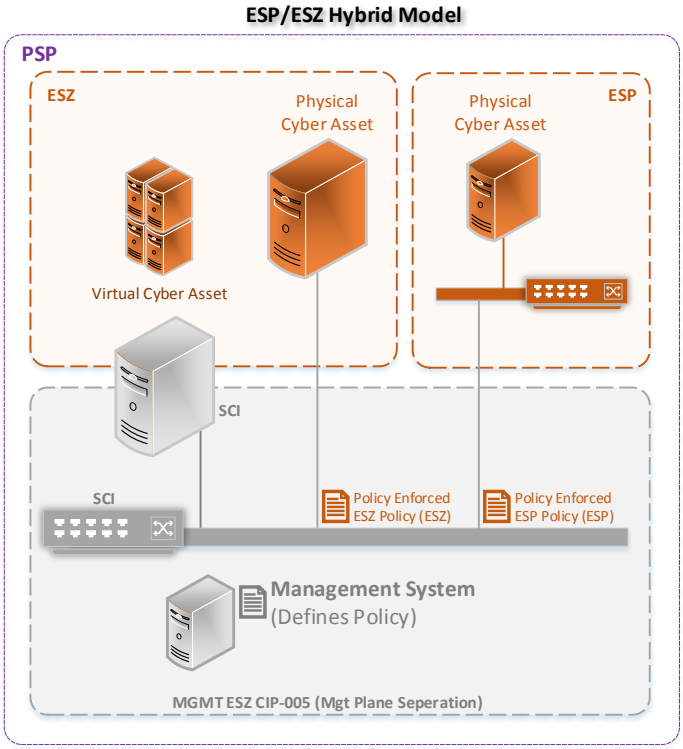
- Declaring the VCAs that share compute resources (CPU, memory) or are within the same ESZ or ESP with a BES Cyber System as associated PCAs which will require they meet the same security requirements (high water marking); or
- Configuring the virtualization infrastructure to place VCA's of differing impact or trust levels into differing ESZ's and configuring affinity controls to these zones such that hypervisors do not allow workloads in these differing zones to simultaneously exist or execute on the same hypervisor.

Hybrid Virtual/Physical Scenarios with ESP/ESZ's

Typically, virtualized environments will use the ESZ structure and physical asset environments will use the ESP structure for meeting CIP-005 requirements. However, numerous scenarios will include a hybrid of both virtual and physical Cyber Assets. An entity could configure their SCI so that both virtual and physical Cyber Assets are in the same ESZ to reduce the number of zones required to implement the new concepts. The following series of diagrams illustrates some hybrid scenarios.

Hybrid ESP/ESZ Inside of a Single PSP

In this scenario, a virtual Cyber Asset and physical Cyber Asset are shown with logical isolation (ESZ) provided by SCI using a policy enforced ESZ. Another physical Cyber Asset is show using an ESP for logical isolation. In this case, the same SCI is used to provide both the equivalent EAP functionality and logical isolation (ESP) via a policy enforced ESZ. Note that the management plane of the SCI resides within its own ESZ.

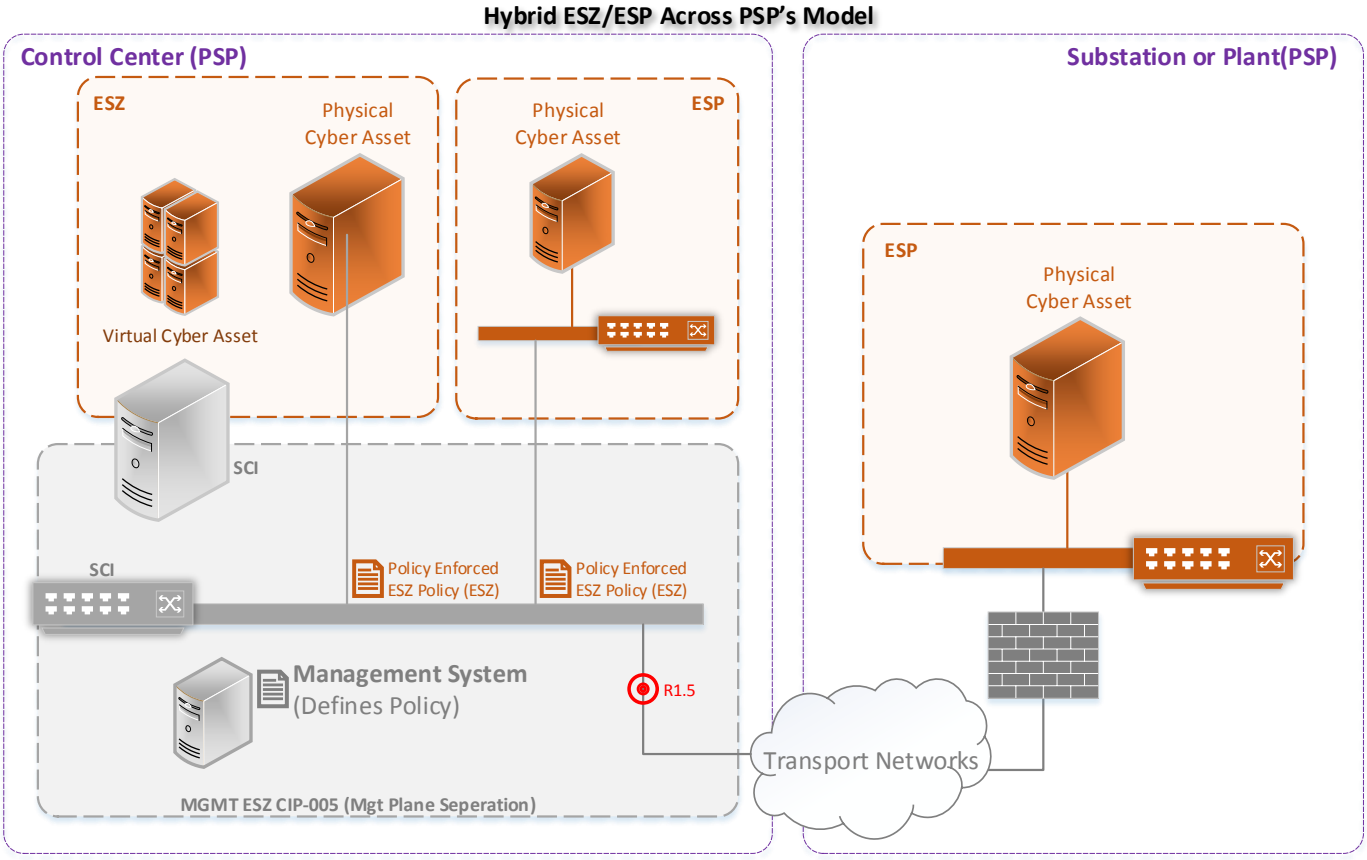


Hybrid ESP/ESZ across PSP's

In the left portion of this scenario (the Control Center), a virtual Cyber Asset and physical Cyber Asset are shown with logical isolation provided by SCI using a policy enforced ESZ. Another physical Cyber Asset is shown using an ESP for logical isolation. In this case, the same SCI is used to provide both the equivalent EAP functionality and logical isolation (ESP) via a policy enforced ESZ. Note that the malicious communications detection required for the Control Center (R1.5) is being provided by the SCI.

In the right portion of the drawing (Substation or Plant), another physical Cyber Asset is shown where its logical isolation is provided by an ESP. A physical firewall (EACS/SCI) is used to provide the logical isolation.

Note that the management plane of the SCI resides within its own ESZ.



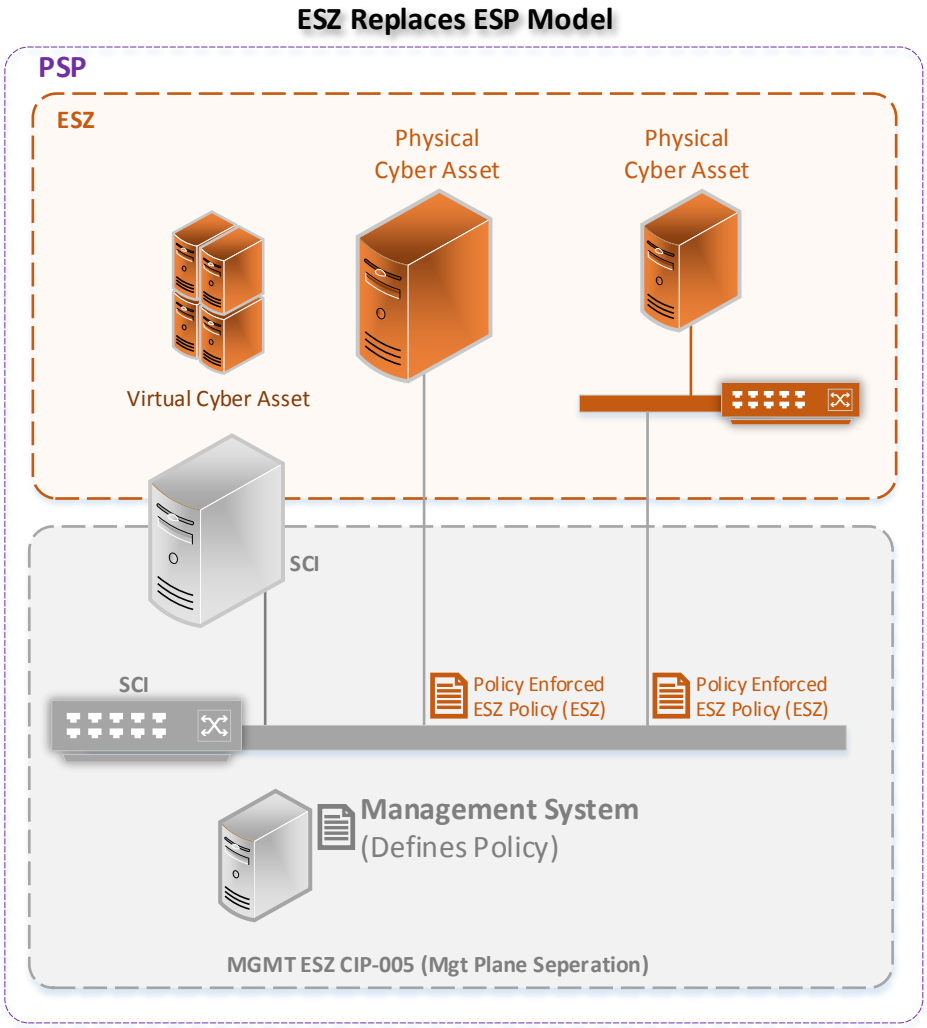
Combined ESZ for Cyber Assets and Virtual Cyber Assets

In this drawing, virtual and physical Cyber Assets are located within a single ESZ where the logical isolation is provided by the SCI. Previously, this would have required a physical firewall to both provide an EAP and logical isolation. In the left portion of the drawing, a VCA and supporting SCI are being utilized where logical isolation (ESZ) is being provided by the SCI using a policy enforced ESZ. The SCI is also enforcing logical isolation for the physical Cyber Assets by configuring the appropriate policy enforced ESZ. This effectively converts what would have been an ESP for the physical Cyber Assets into a similar policy enforced ESZ used by the virtual Cyber Asset where traditional EAP functionality is now provided by the SCI. This has the following advantages:

a) Access control for this environment is centrally managed and a single policy for the ESZ is enforced for virtual and physical Cyber Assets.

b) For applicable Control Centers, it alleviates the need for a multiple ESPs or ESZs and methods to detect malicious communication for network traffic between them within the Control Center.

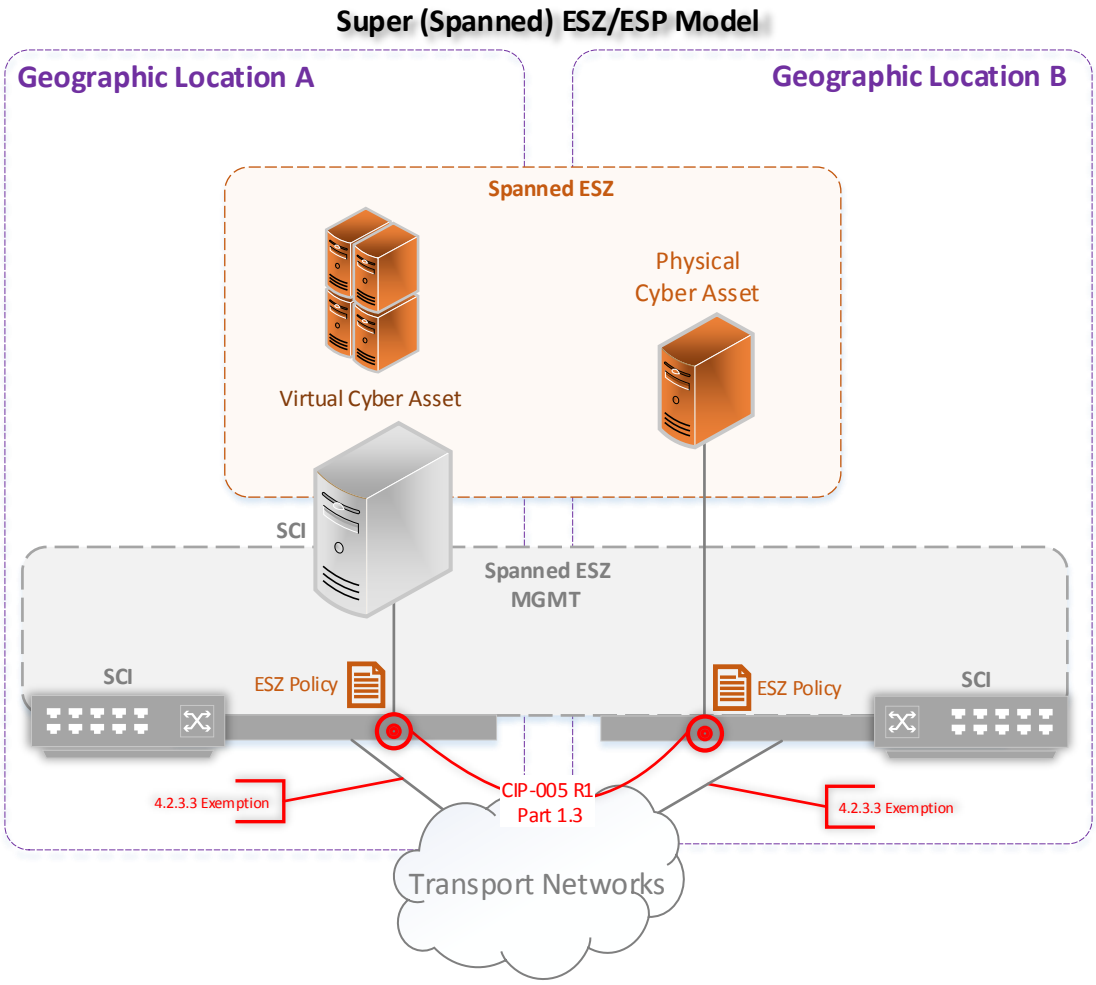
Note that the management plane of the SCI resides within its own ESZ.



Spanned ESZ Model

In this model, two different geographic locations are connected by a transport network. The transport network is utilized to span the SCI and the same logical isolation (a single ESZ) between these two locations. In one location, a virtual Cyber Asset running on SCI is within the policy enforced ESZ. In the other location, a physical Cyber Asset is within the same ESZ that is spanned between the two locations. This allows the exact same ESZ policy to be enforced across the locations as well. Note that malicious communication detection is not required for network traffic within the same ESZ, even if it flows between the locations. However, the network data traversing the transport network must still be protected under CIP-005-7 Requirement R1.3 or CIP-012-1 where applicable.

Note that as the same management plane of the SCI is spanned between locations, the ESZ protecting the SCI management plane is also spanned as well.



EACMS/PACS Glossary Terms

As technologies and attacks have advanced and become more complex, entities are becoming more interested in partnering with outside and government security services. These includes services like NERC's Cyber Security Risk Information Sharing Program (CRISP), Cybersecurity for the Operational Technology (OT) Environment (CYOTE), and those of other external security services and internal monitoring centers. Going forward, these types of service and providers will become more cloud based. Security service providers have visibility into emerging threats and trends that come through their extensive collections of information. Analysis of this information can then be shared more broadly, improving the overall cybersecurity posture and reliability of the BES through early detection of compromise and the ability to monitor for threats and indicators of compromise (IOCs) at machine speeds.

Under the current body of CIP Standards, using the types of services that include electronic access monitoring data (not involved in the actual control of electronic access) may bring all Cyber Assets involved into scope as an EACMS. This may discourage or even preclude entities from using these services based on the Cyber Asset level requirements of an EACMS. These limitations affect personnel, physical security, patching, baselines, and other requirements that focus on a Cyber Asset. Entities may also be discouraged from providing and correlating security events across enterprise and control networks, even though most cyber-attacks against control systems today enter through business networks. There is great value in correlating security events seen across enterprise and OT networks that may be discouraged or precluded through the "M" in EACMS growing to include much an enterprise's other monitoring only Cyber Assets.

The cyber systems that do perform electronic access control will remain as they are today in the standards. Those cyber systems, such as firewalls and routers with ACLs and other systems that do perform access control and actively protect the networks to which BES Cyber Systems are connected should not change. However, the monitoring and logging aspect of EACMS presents a different risk of information protection. The creation of two different defined terms recognizes this. EACS represents those systems that do control electronic access and will essentially be a drop-in replacement for today's EACMS.

The parallel also exists for PACS where a differentiation between systems that control physical access can be made with systems that only monitor or log access information.

External Routable Connectivity (ERC) and Interactive Remote Access (IRA)

External Routable Connectivity (ERC) is used in the CIP standards for different purposes, including:

1. Establishing when EAPs are required
2. Limiting scope of ~38 requirement parts to those locations that have a high enough level of remote connectivity to support the requirement

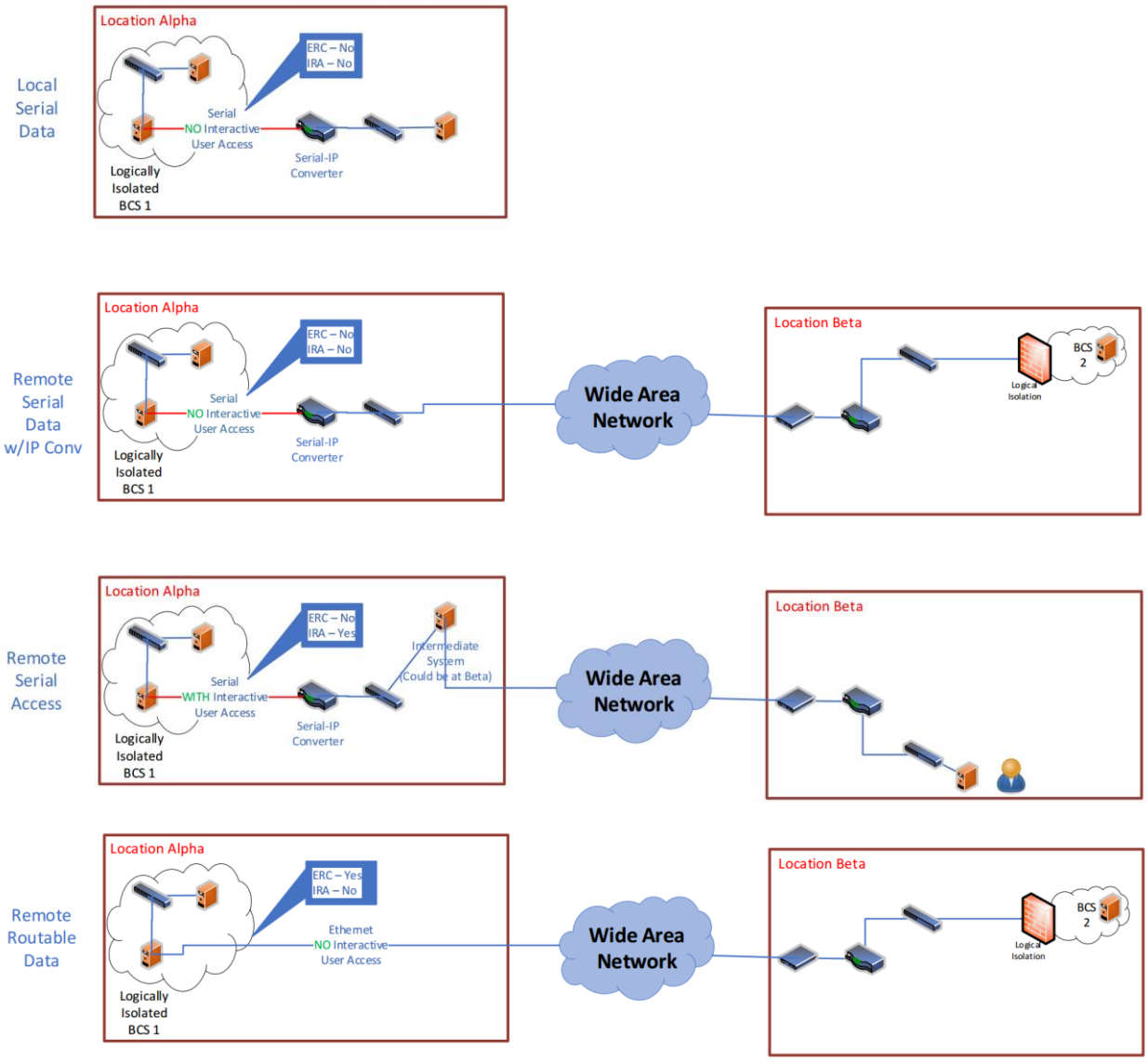
The move to the more objective-based requirements shifts the obligation away from implementing access controls at a defined cyber asset interface point (EAP). The objective can now be accomplished without dictating any architecture or access control method, thus eliminating ERC's role in determining EAPs. However, ERC is still needed as a scoping mechanism for the vast scale of systems and their components within a geographically distributed BES. Many requirement parts should be scoped based on whether the system has ERC for the following reasons:

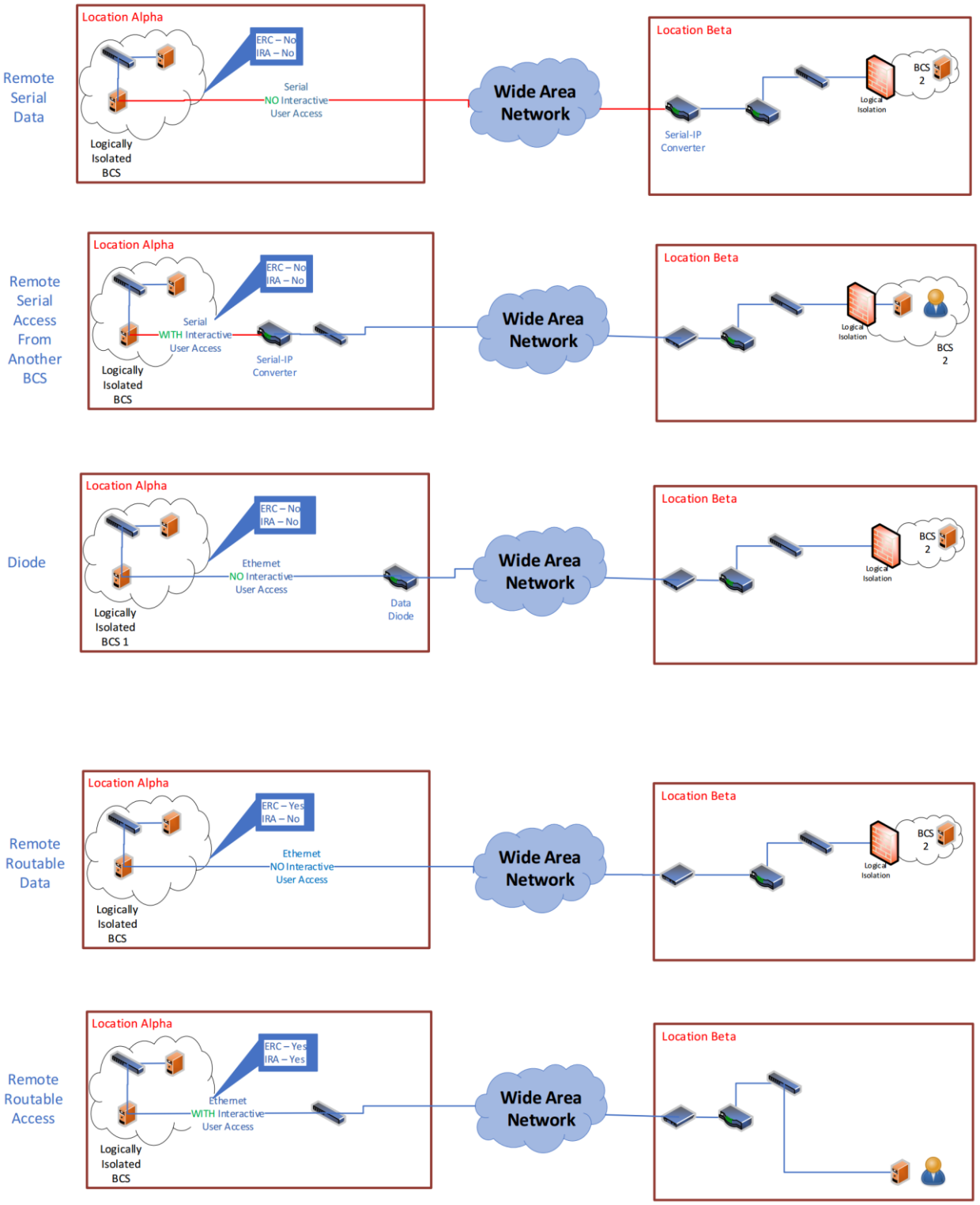
- The risk is increased for systems with ERC. The requirement should apply to those systems with an increased attack surface and risk due to their connectivity/accessibility.
- Locations that have legacy connectivity such as non-routable serial leased circuits should not have to increase their level of remote connectivity and attack surface to meet security requirements. For example, it would

not be advisable to put in an IP network into a site to get SNMP traps out for alerts if a serial circuit with reduced attack surface is all that is needed for operations.

One issue with the ERC definition from the V5TAG transfer document has been that of BES Cyber Assets (BCA) that only speak non-routable protocols over a serial port. These BCAs are not in an ESP and therefore can be considered to not have ERC because it is defined in terms of an "associated ESP." These BCAs, however, can have Interactive Remote Access through an upstream serial-to-IP conversion. The SDT has kept ERC as-is with only conforming changes in order to not disrupt its scoping function as noted above. However, the IRA definition has been modified so that a device with only a serial, non-routable connection can now have IRA and be subject to CIP-005 R2. Appropriate controls (CIP-005 R2) are now required for these Interactive Remote Access sessions without regard to ERC.

The following diagrams show different scenarios and whether ERC and/or IRA exist in the situation.





Assets with Multiple Classifications (PCA, EACS, IS, SCI, etc.)

The definitions created in support of the CIP Standards have historically included overlap. In this current version of CIP-005-7, the definition of PCA is updated with conforming changes that include Virtual Cyber Assets, as well as

those that share computer resources with BES Cyber Systems. Additional definitions such as Shared Cyber Infrastructure and Virtual Cyber Asset will add to the possibility of additional instances of assets or systems meeting multiple definitions, such as EACS that are also PCAs, or SCI that is also an EACS.

These definitions are used in both the Applicable Systems column as well as within the language of the Requirement. The fact that one asset or system may have multiple classifications does not pose a significant challenge as long as the Responsible Entity ensures that all Requirements that pertain to ANY of the classifications are applied. In other words, if an asset or system meets both the SCI and the EACS definition, requirements that apply to either definition would be applicable.

Requirement R1

General Considerations for Requirement R1

Requirement R1: Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-005-7 Table R1 – Logical Isolation. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same Day Operations].*

Rationale

Requirement 1 is designed to implement various forms of logical isolation between systems in different ESPs or ESZs and have the access controlled between them. The ESP model continues unchanged as the 1.2 requirement part moves to an objective-based requirement that the EAP model can meet. However, requirement R1 allows for other models (such as zones and zero-trust models) that can also meet the objective in 1.2. For the ESZ concept, the requirement has new requirement parts to cover what systems can reside in what zones to mitigate the risks of “mixed trust” environments that are possible on shared infrastructure.

Requirement R1 Part 1.1

Part	Applicable Systems	Requirements	Measures
1.1	High Impact BES Cyber Systems and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI Medium Impact BES Cyber Systems connected to a network via routable protocol and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI	All applicable systems shall reside within one or more defined ESPs or ESZs.	An example of evidence may include, but is not limited to, a list of all ESPs or ESZs with all uniquely identifiable applicable systems.

Rationale

This requirement part gives the entity the option to use either the ESP model or the ESZ model for implementing the logical isolation of the applicable systems. For a discussion of the ESZ option, see the rationale for the ESZ and SCI definitions above, the General Considerations section above, as well as the diagram depicting various ESZ configurations in Attachment 1.

Requirement R1 Part 1.2

Part	Applicable Systems	Requirements	Measures
1.2	Electronic Security Perimeters and Electronic Security Zones created in Part 1.1.	Require inbound and outbound logical access permissions, including the reason for granting access, and deny all other logical access by default. Excluding time-sensitive protection or control functions between intelligent electronic devices (e.g., communications using protocol IEC TR-61850-90-5 R-GOOSE).	An example of evidence may include, but is not limited to, architectural diagrams that detail how network communication is limited and a list of rules (firewall, access control lists, software defined policies, etc.) that demonstrate that only permitted access is allowed and that each access rule has a documented reason.

Rationale

Removal of Electronic Access Point (EAP):
The SDT is proposing the removal of EAP as a definition, therefore, the applicability of CIP-005-7 R1.2 also needs to change. The SDT chose ESP(s) and ESZ(s) created in Part 1.1 as the Applicable Systems where Registered Entities are required to apply the inbound and outbound access controls to replace the term EAP. By doing so, current Access Control Lists in-place for established EAPs continue to serve the same purpose and should remain compatible with this requirement part. Also see the discussion of the ESZ and EAP terms above.

Requirement Parity within ESZ to establish security level and address "mixed trust":
The SDT chose to establish the ESZ at a single trust level by assigning the same set of requirements throughout the CIP standards to systems that reside within an ESZ. The goal of this is to minimize the ability of an attacker to pivot from one system to another within an ESZ. An example of this is the threat of an attacker escaping a virtual machine to access the host hypervisor and other Virtual Machines (VMs). If there were systems within the ESZ that were not held to the same trust level, compromising those systems could be potentially easier, which would allow an attacker to pivot and compromise systems to the higher impact targets within the same ESZ.

For example, if a Protected Cyber Asset (PCA) within an ESZ is not subject to the same CIP-004 requirements for personnel accessing the PCA as it is for the BES Cyber Systems within the same ESZ, it could be used as a "pivot" for allowing unauthorized access to the BES Cyber Systems within the ESZ.

In future formal postings of the CIP standards with conforming changes applied, the affected requirements will have "hosted on SCI" phrasing within the "Applicable Systems" column. These requirements establish a single security or trust level for the applicable systems within an ESZ. Each of these requirements serves a specific security need, and if missing, would reduce the security level of the hosted virtualized systems potentially reducing the security level of the associated BCS.

The obligations for electronic access controls exclude communications between intelligent electronic devices that use routable communication protocols for time-sensitive protection or control functions, such as IEC TR-61850-90-5 R-GOOSE messaging. Time-sensitive in this context generally means functions that would be negatively impacted by the latency introduced in the communications by the required electronic access controls. This time-sensitivity exclusion does not apply to SCADA communications which typically operate on scan rates of 2 seconds or greater. While technically time-sensitive, SCADA communications over routable protocols can withstand the delay introduced by electronic access controls. Examples of excluded time-sensitive communications are those communications which may necessitate the tripping of a breaker within a few cycles. A Responsible Entity using this technology is not expected to implement the electronic access controls noted herein. This exception was included so as not to inhibit the functionality of the time-sensitive characteristics related to this technology and not to preclude the use of such time-sensitive reliability enhancing functions.

Requirement R1 Part 1.3

Part	Applicable Systems	Requirements	Measures
1.3	Electronic Security Zone or Electronic Security Perimeter that spans more than one geographic location containing: • High Impact BES Cyber Systems • Medium Impact BES Cyber Systems	Protect the confidentiality and integrity of the data traversing communication networks and data communication links used to extend an applicable ESP or ESZ, excluding Real-time Assessment and Real-time monitoring data while being transmitted between Control Centers subject to CIP-012 and excluding time-sensitive protection or control functions between intelligent electronic devices (e.g., communications using protocol IEC TR-61850-90-5 R-GOOSE).	Evidence may include, but is not limited to, architecture documents detailing the methods used to mitigate the risk of unauthorized disclosure. Examples include physical protection and the points where encryption initiates and terminates.

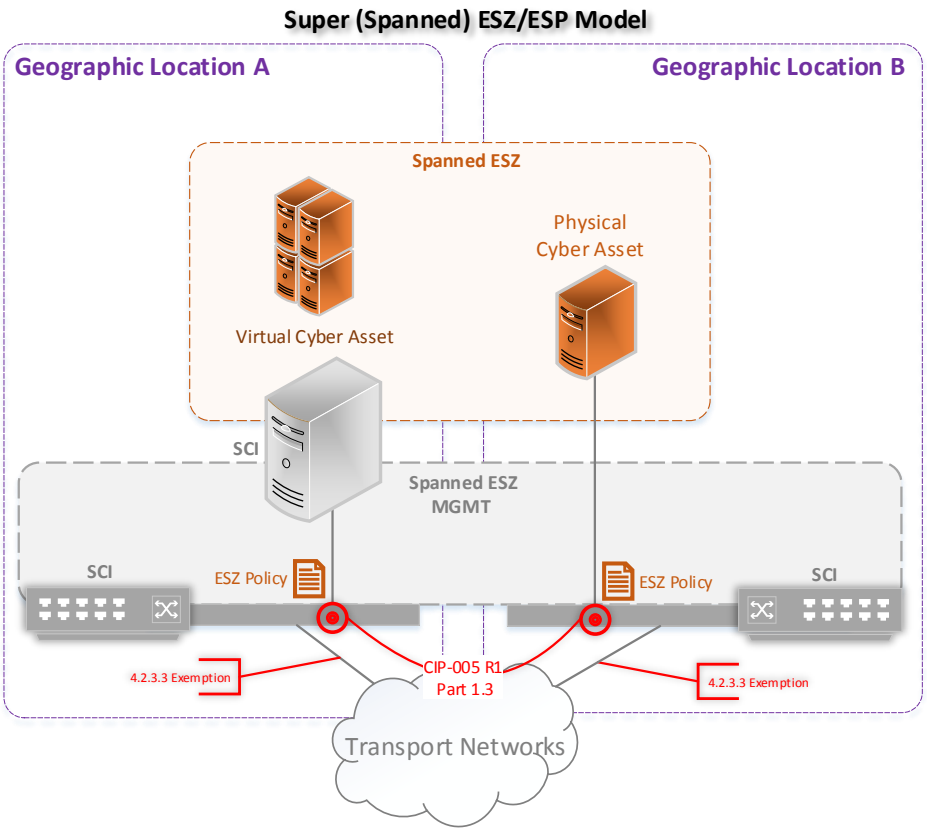
Rationale

Part 1.3 is a new requirement intended to protect the confidentiality and integrity of data flowing between an entity's facilities when that data is contained within a single ESP or ESZ that spans more than one geographic location, commonly referred to as a 'Super ESP.'

One of the issues with the ESP construct carried forward into the logical isolation model is the situation where entities have BES Cyber Systems that include components at separate locations. For example, if an entity has a need to replicate data at high speed between two databases in two different geographic locations to improve the

resilience and reliability of BES Cyber Systems, the entity may have issues with the 4.2.3.2 exclusion in the standards that exempts the network and communications gear that is "between discrete ESPs." If the protocol is not routable then no ESP can be created. The entity needs to be able to have a "Super-ESP" that can span more than one location.

The ESP model, along with the 4.2.3.2 exclusion within the CIP standards applicability does not lend itself to this construct. As technology evolves, there will be many more instances where a BES Cyber System may need to span locations. Traditionally this situation could be addressed by installing an EAP at each site as an ESP boundary that would then allow the communications equipment between the sites to be subject to the exemption if routable protocols are used.



The 'Super ESP' construct has been addressed with a new exclusion and a new requirement (CIP-005 R1.3). The new exclusion in 4.2.3.3 allows Cyber Assets associated with communication networks and data communication links used to extend an ESP or ESZ to more than one geographic location to be exempt from the standard since many of these Cyber Assets may be owned by carriers. However, the new R1.3 in CIP-005 requires that data over this exempted communication be protected to preserve its integrity and confidentiality, with the exception of time sensitive protection functions.

The exemption within this requirement part for "Real-time Assessment and Real-time monitoring data while being transmitted between Control Centers subject to CIP-012" does not exempt it from protection under the CIP standards as it is covered by CIP-012. The intent of this exemption is to keep any issues with CIP-012 compliance from becoming a CIP-005 issue as well if the two control centers in question also have the "Super-ESP" implemented.

Requirement R1 Part 1.4

Part	Applicable Systems	Requirements	Measures
1.4	High Impact BES Cyber Systems with Dial-up Connectivity and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI Medium Impact BES Cyber Systems with Dial-up Connectivity and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI •	Perform authentication when establishing Dial-up Connectivity with applicable systems, per system capability.	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.

Rationale

CIP-005-7, Part 1.4 reinforces that dial-up connectivity should perform authentication whenever possible so that the BES Cyber System is not directly accessible with only a phone number. It has been changed to apply to virtualized environments as well and update the TFE requirements to the “per system capability” language.

Requirement R1 Part 1.5

Part	Applicable Systems	Requirements	Measures
1.5	High Impact BES Cyber Systems and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI Medium Impact BES Cyber Systems at Control Centers and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI	Have one or more methods for detecting known or suspected malicious routable Internet Protocol (IP) communications to or from ESPs or ESZs.	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

CIP-005-7 requirement 1.5 reflects the retirement of the term EAP in favor of utilizing the terms ESP and ESZ. The intent of requirement 1.5 is to detect known or suspected malicious communications at the ESP or ESZ boundaries.

The use of "to or from" in the requirement is to solidify where the detection should take place, which is at the boundary of the ESP or ESZ and not communications within the ESP or ESZ. The use of the phrase “routable Internet Protocol (IP) communications” is intended to eliminate internal storage transport protocols including, but not limited to Fibre Channel, iSCSI, and InfiniBand from the scope of this requirement as well as serial communications.

The change in the applicable systems is to provide both forward and backward compatibility within the same requirement.

Requirement R1 Part 1.6

Part	Applicable Systems	Requirements	Measures
1.6	Shared Cyber Infrastructure that hosts High Impact BES Cyber Systems Shared Cyber Infrastructure that hosts Medium Impact BES Cyber Systems	Management systems may only share CPU, memory, and ESZ or ESP with other management systems and the management plane.	Examples of evidence may include, but is not limited to, documentation that includes the configuration of systems that enforce authentication and isolation such as: • Logically isolated out-of-band network infrastructure configuration (ACL, VLAN, VXLAN, MPLS) • Physical isolated out-of-band network for dedicated management interfaces, embedded management interfaces • Compute configuration showing the isolation of the management plane resources (e.g., hypervisor, containers)

Rationale

The SDT is proposing a new Requirement, CIP-005-7 Requirement R1, Part 1.6. The purpose of this new Requirement is to separate the management plane of SCI from the data plane.

As virtualized servers, networks, switches, firewalls, and storage are logical constructs, controlling access and communications to the management plane of these systems becomes imperative. Access to the management plane (interface, console, etc.) allows users to create, modify, or delete objects or entire infrastructures, or move objects from one zone or network to another. Therefore, administrative level or "management plane" access to the SCI is critical to the security and reliability of the hosted systems. By isolating the management interface of these devices from the larger audience of users that can access the data plane, the threat base is reduced to the group of users with access to the administrative functions.

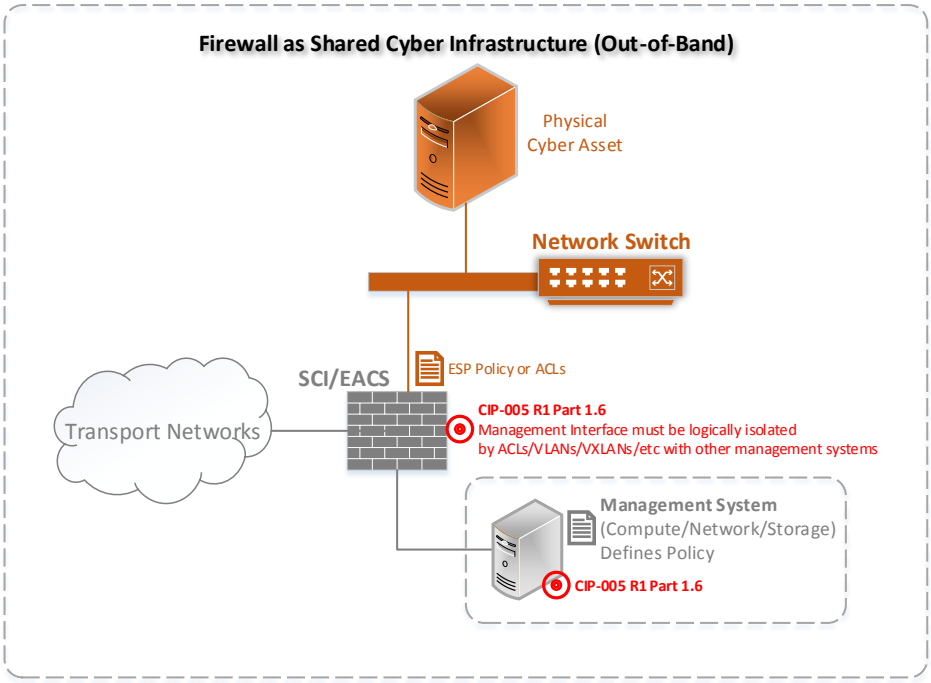
The methods used to separate the management plane from the data plane developed quickly as systems moving to the cloud increased. For a cloud-based hosting facility to be successful, the tenants must share hardware resources (SCI as defined here) but have no ability to access or modify other tenants or their configuration. Cloud technology was forced to enhance existing methods and develop new methods to accomplish this separation.
SCI presents the same issue for in-house (on-premise) virtualization environments. CIP-005 R1.6 will mitigate that issue by bringing the isolation of the management plane into the scope of the CIP standards. This is accomplished by requiring that entities allow management systems to share CPU and memory (e.g. hypervisors) only with other management systems. It also requires that management systems share an ESZ only with other management systems.

Because hypervisors give us the ability to use affinity rules to determine what VMs use what resources, affinity and anti-affinity rules are a critical part of the isolation solution for management systems hosted on SCI. An affinity rule will ensure a group of virtual machines are only allowed to reside on a group of hypervisors. The use of an anti-affinity rule will ensure another group of VMs cannot reside on the group of hypervisors reserved in the previous affinity

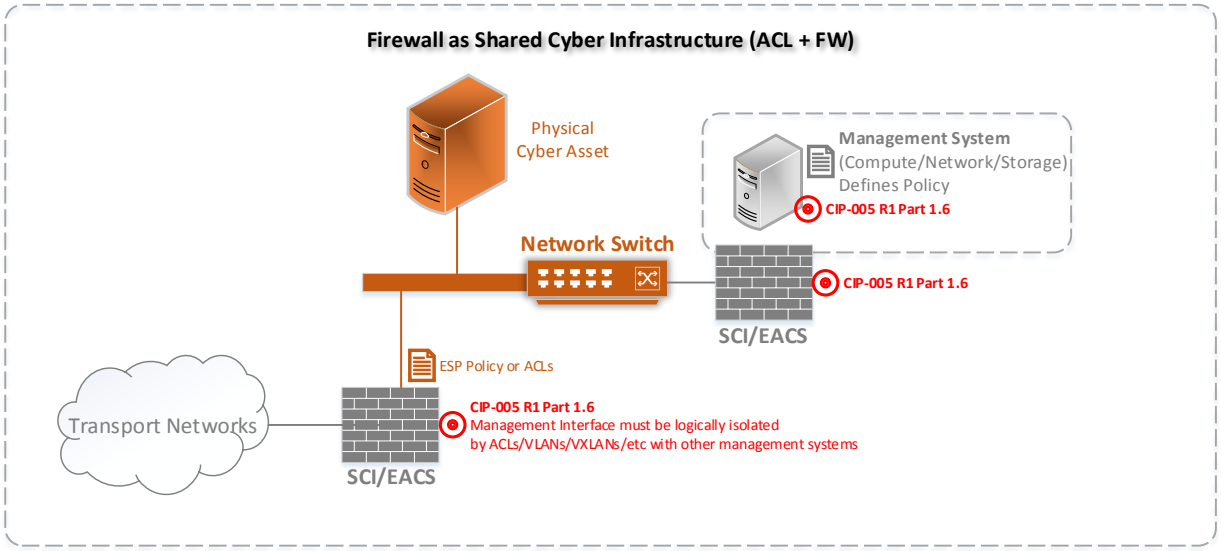
rule. While different hypervisors have different methods for achieving this, the idea is the same across all mass market hypervisors.

The statement "or performs logical isolation for an ESZ or ESP" is found within the Shared Cyber Infrastructure definition. This inclusion is intended to ensure that devices that provide logical isolation for an ESZ or ESP have protection for the associated management systems (management plane). This inclusion means the management plane of firewalls or network switches that provide logical isolation to an ESP, ESZ, or within Shared Cyber Infrastructure now fall within scope of R1.6. It is not intended for network switches that are part of a system and are not providing logical isolation between ESPs or ESZs. The following diagrams outline numerous options that help to further clarify the intent of R1.6 as it applies to firewalls and network switches that implement ESP or ESZ logical isolation.

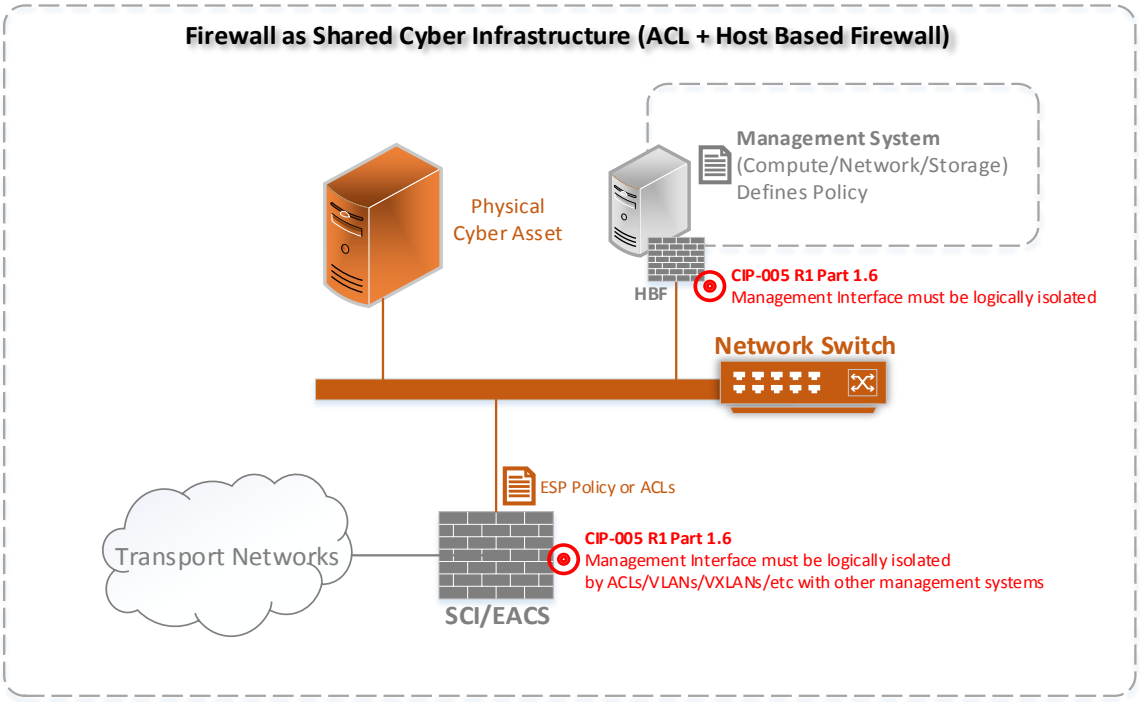
The option below shows the typical out-of-band management of the SCI by putting the management system on a separate interface. This keeps the management system in an ESP or ESZ not shared with other non-management systems. The network switch is not used to perform logical isolation.



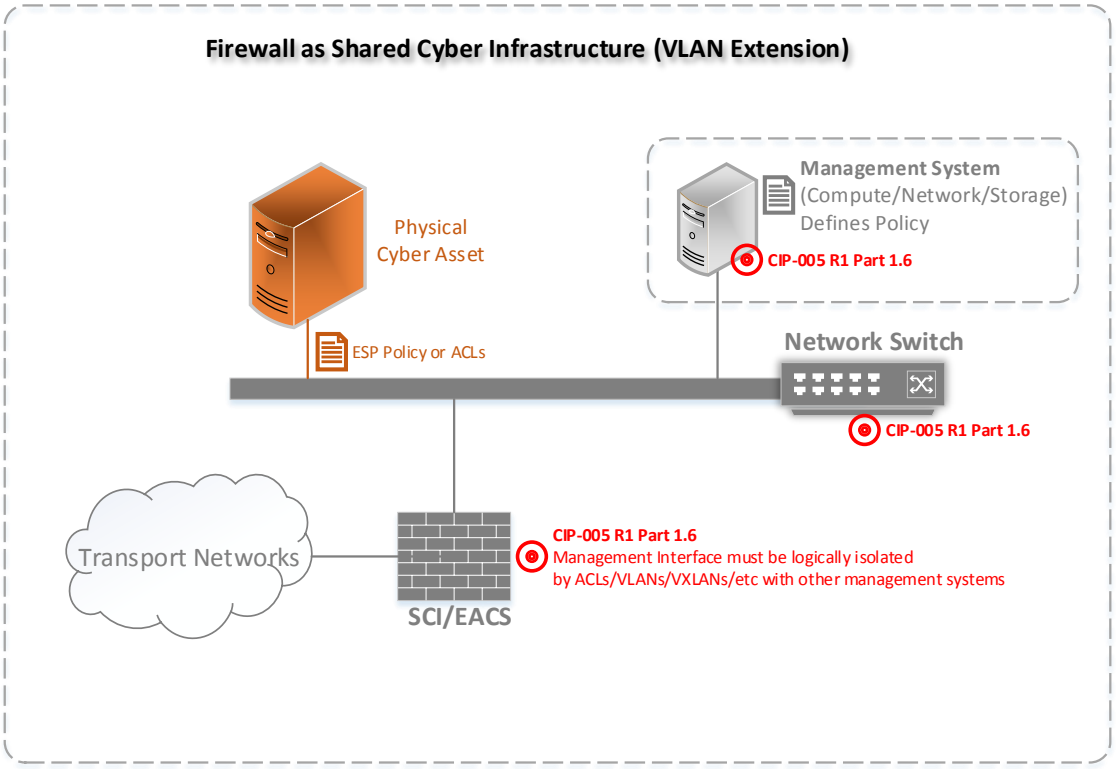
The option below depicts a management system that is located at a site with one network switch. Some sort of logical isolation is required so that the management system is not visible to those with access to the Cyber Asset on the same switch. Another firewall is implemented here to put the management system in an ESP or ESZ separate from the other Cyber Assets. The network switch is not used for logical isolation.



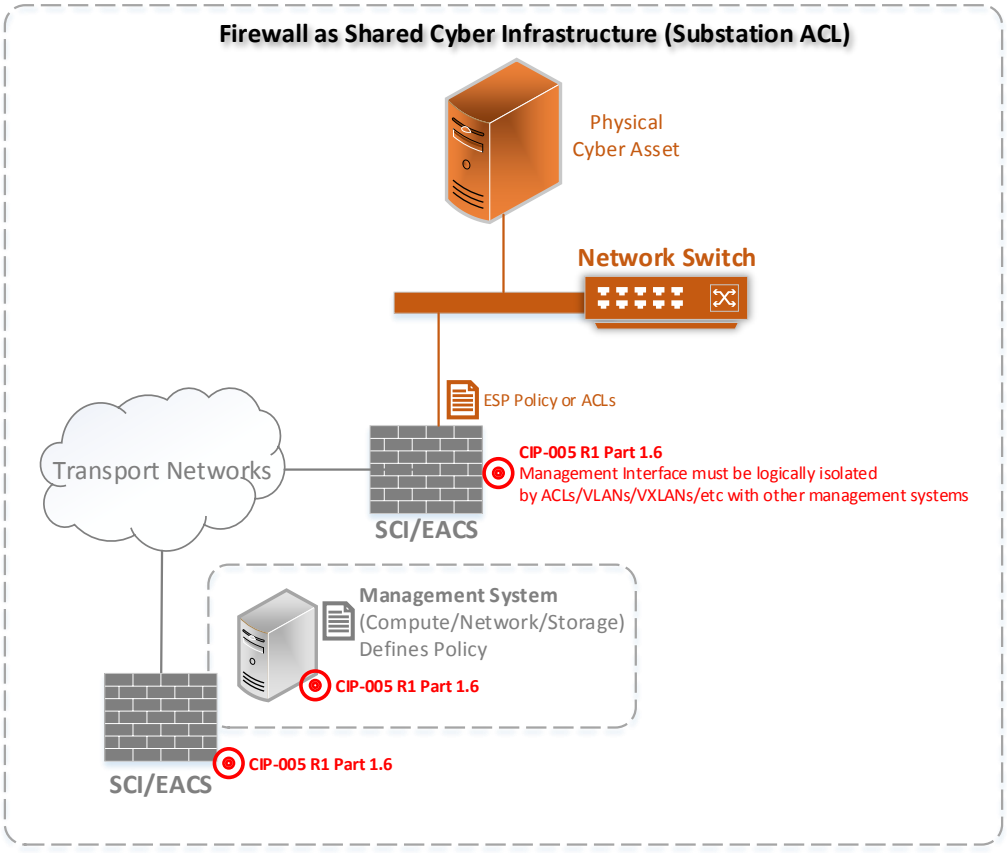
In the option below, the same situation exists, but instead of a separate physical firewall a host based firewall is used on the management system to logically isolate it.



In the option below, the management system is connected to the network switch and the switch is used for the logical isolation. Virtual LANs (VLANs) are configured in the switch along with ACL's in the firewall in order to implement the two different ESZs to isolate the management system. The network switch itself now also becomes SCI and it's management plane now must be in the management ESZ as well.



In the option below, a centralized management system is depicted at another location. ACLs are implemented in the intervening firewalls (SCI) such that the access to the management plane of those firewalls is only allowed to the centralized management system.



Requirement R2

R2. Responsible Entity shall implement one or more documented processes that collectively include the applicable requirement parts, per system capability, in *CIP-005-7 Table R2 –Remote Access Management* for all remote access that originates from outside of any of the entities' ESP's or ESZ's containing high or medium impact BES Cyber Systems or associated SCI. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same Day Operations]*

General Considerations for Requirement R2.

Rationale

This requirement added wording for ESZs containing either high or medium impact BES Cyber Systems or associated SCI to provide the equivalent logical protections for remote access that existed before. The wording for existing ESPs was retained for backward compatibility purposes to CIP-005-6.

Previously, the applicability of the remote access was included within the definition of IRA, which included access that did not originate from within another of the entity's ESPs. That applicability has been removed from the definition (see discussion of IRA above) and placed within the requirement so that the definition does not need to change when the applicability of a requirement that uses it changes.

Requirement R2 Part 2.1

Part	Applicable Systems	Requirements	Measures
2.1	High Impact BES Cyber Systems and their associated: • PCA • SCI Medium Impact BES Cyber Systems with IRA and their associated: • PCA • SCI	Ensure that Interactive Remote Access is through an Intermediate System that is not inside an applicable ESP or ESZ.	Examples of evidence may include, but are not limited to, network diagrams or architecture documents.

Rationale

The Applicable Systems section of this requirement was updated to include SCI associated with high and medium impact BES Cyber Systems. This was done to ensure that same safeguards for remote access methods and technologies exist for the applicable SCI as the high and medium impact BES Cyber Systems and associated PCA's being hosted on that SCI. Backwards compatibility with CIP-005-6 is maintained for entities that do not currently use SCI.

For Medium Impact BES Cyber Systems, the Applicable Systems wording was updated from "with External Routable Connectivity" to "with IRA". This was done to cover serial connectivity associated IRA for those applicable systems without External Routable Connectivity (ERC). This aspect of IRA was missing from earlier versions of CIP-005. This

change is intended to mitigate risks associated with a possible external (to the entity) attack vector in situations where serial connectivity is converted to network connectivity using a terminal server type device. This is one of the issues noted by the V5TAG. Please refer to the section of this document entitled "External Routable Connectivity (ERC) and Interactive Remote Access (IRA)."

The inclusion of the wording for "associated SCI" is intended to target the management plane of the associated SCI. This is to ensure that the management plane of the SCI being used to support BES Cyber Systems is also protected in an equivalent manner.

Backwards compatibility with CIP-005-6 is maintained except in the above situations.
The requirement language itself was simplified. Note that the definitions of IRA and IS have been updated. Please note that the definition of IRA was changed to include serial communications connections. This change maintains backwards compatibility with CIP-005-6 except where serial connectivity is being used for IRA.
The required location of an Intermediate System was within the definition previously. The definition of IS has been simplified and its required location (not inside an applicable ESP or ESZ) is now within the requirement rather than the definition.

Requirement R2 Part 2.2

Part	Applicable Systems	Requirements	Measures
2.2	Intermediate Systems associated with High Impact BES Cyber Systems. Intermediate Systems associated with Medium Impact BES Cyber Systems.	Protect the confidentiality and integrity of Interactive Remote Access between the client and the Intermediate System.	An example of evidence may include, but is not limited to, architecture documents detailing where encryption initiates and terminates.

Rationale

The Applicable *Systems* was changed to IS from high or medium BES Cyber Systems and associated PCA's. This change better reflects that this requirement is associated with the IS itself.

The requirement was changed from a specific technical based requirement for encryption to an objective based requirement to protect the IRA session. The proposed language of this requirement takes into account the possibility that other equally effective methods could be developed and deployed. This also prevents outdated encryption methods from being utilized.

The changed requirement is backwards compatible with the CIP-005-6 except where outdated encryption methods have been used.

Requirement R2 Part 2.3

Part	Applicable Systems	Requirements	Measures
2.3	Intermediate Systems associated with High Impact BES Cyber Systems. Intermediate Systems associated with Medium Impact BES Cyber Systems.	Require multi-factor authentication to IS.	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.

Rationale

The Applicable Systems was changed to IS from high or medium BES Cyber Systems and associated PCA's. This change better reflects that this requirement is associated with the IS itself. Note that serial connection-based IRA is now included due to the IRA definition change. The requirement itself was not changed.

The changed requirement is backwards compatible with the CIP-005-6 except where serial connection-based IRA is being utilized.

Requirement R2 Parts 2.4 – 2.5

Part	Applicable Systems	Requirements	Measures
2.4	High Impact BES Cyber Systems and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI Medium Impact BES Cyber Systems and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI •	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), such as: • 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.
2.5	High Impact BES Cyber Systems and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI Medium Impact BES Cyber Systems and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI •	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.

Rationale

The Applicable Systems section was changed to include associated SCI, PACS hosted on SCI, EACS hosted on SCI, EAMS hosted on SCI. This change is needed due to the possibility of "differing trust levels" when these types of assets utilize the same SCI. Please refer to the section in this document entitled 'Shared infrastructure and "Mixed Trust" Risks'. In summary, this change is intended to mitigate the risk associated with "side channel" based attack vectors where it could be possible to compromise one virtual cyber asset and then subsequently access the any other virtual cyber asset running on the same SCI. Also note that serial connection-based IRA is now included due to the change in the

definition of IRA.

The inclusion of the wording for "associated SCI" is intended to target the management plane of the associated SCI. This is to ensure that the management plane of the SCI being used to support BES Cyber Systems is also protected in an equivalent manner

The requirements themselves have not been changed. Note that the requirement includes both vendor based IRA and system-to-system access.

Note that the changes to applicable systems only applies to those virtual cyber assets hosted on the same SCI. These changes don't apply where SCI is not utilized. These changed requirements are backwards compatible with the CIP-005-6 except where SCI is currently being utilized and where serial connection-based IRA is being utilized.

Requirement R2 Part 2.6

Part	Applicable Systems	Requirements	Measures
2.6	Intermediate Systems that are hosted on SCI and are associated with High Impact BES Cyber Systems. Intermediate Systems that are hosted on SCI and are associated with Medium Impact BES Cyber Systems.	IS may only share CPU, memory, and ESZ or ESP with other IS.	An example of evidence may include, but is not limited to, documentation that includes the following: configuration showing that the CPU and memory can only be shared with other IS.

Rationale

This is a new requirement that only applies to IS hosted on SCI. This new requirement is proposed due to the possibility of:

- IS being used by external parties outside of the entities such as vendors; and,
- IS being accessible to external connections outside of the entity such as entity support staff utilizing IRA across an internet connection to support a remote site.

Please refer to the section in this document entitled "Shared infrastructure and "Mixed Trust" Risks" and the subsequent discussion on "affinity". The new requirement is for "affinity" and a separate ESZ.

In summary, this new requirement is intended to mitigate the risk associated with "side channel" based attack vectors where it could be possible to compromise the IS from an external source and then subsequently access the any other virtual Cyber Asset running on the same SCI.

As this is a new requirement only applies to IS hosted on SCI, it is backwards compatible with the CIP-005-6 except where SCI is currently used.

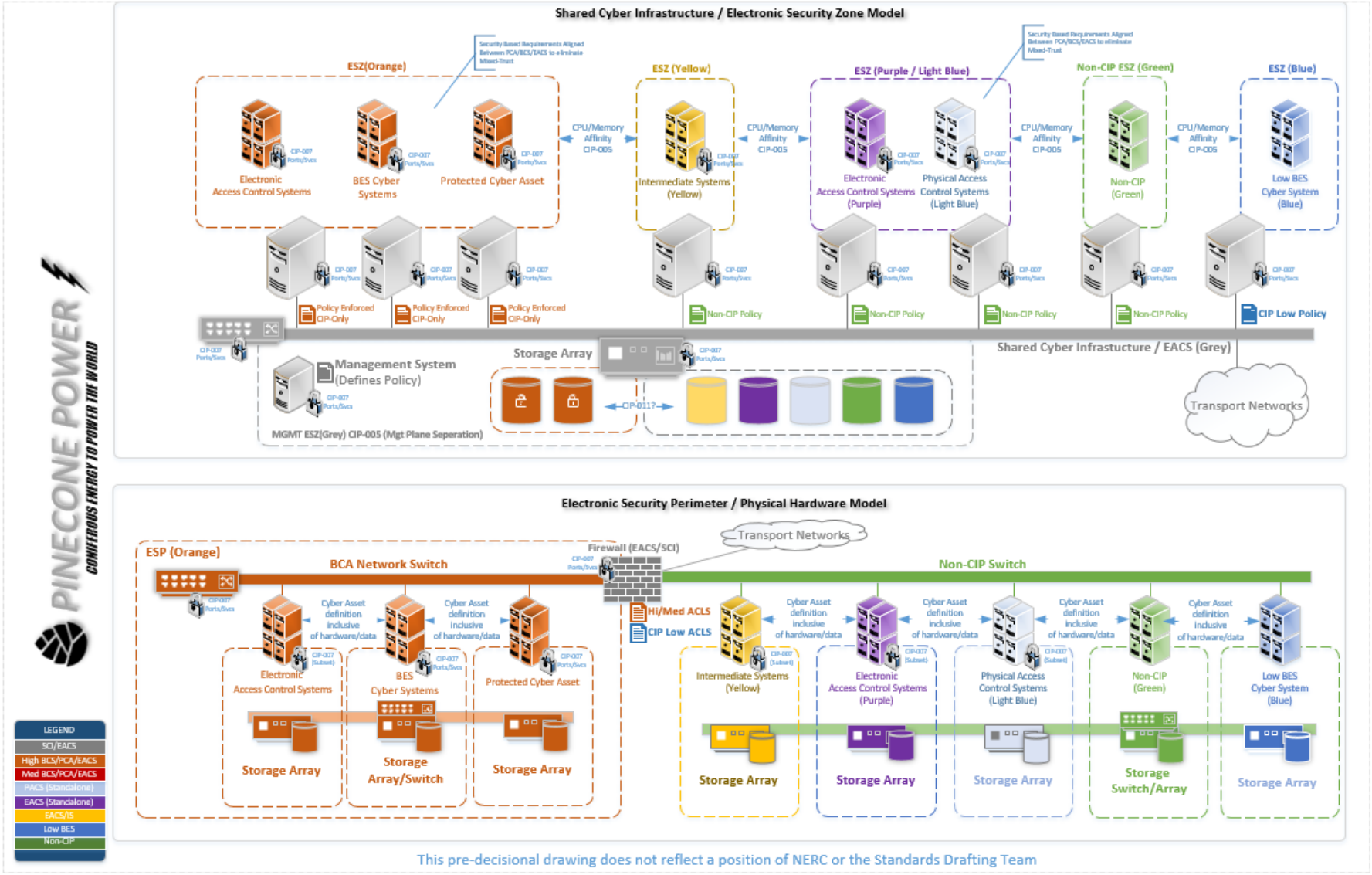
Appendix 1 – ESZ's

This section contains a diagrams for a fictional utility company ("Pinecone Power").

Figure 1 is used to show a virtualized scenario at the top of diagram and contrasts it with a typical physical hardware model on the lower half. The virtualized scenario fully utilizes the ESZ concept and has practically every kind of system hosted within the environment. The color coding (see legend at lower left) depicts the categorization of various components. The diagram shows the different ESZs that would be required and the affinity rules that would be needed between them such that systems of different security levels would not share the same hypervisor with systems in other zones.

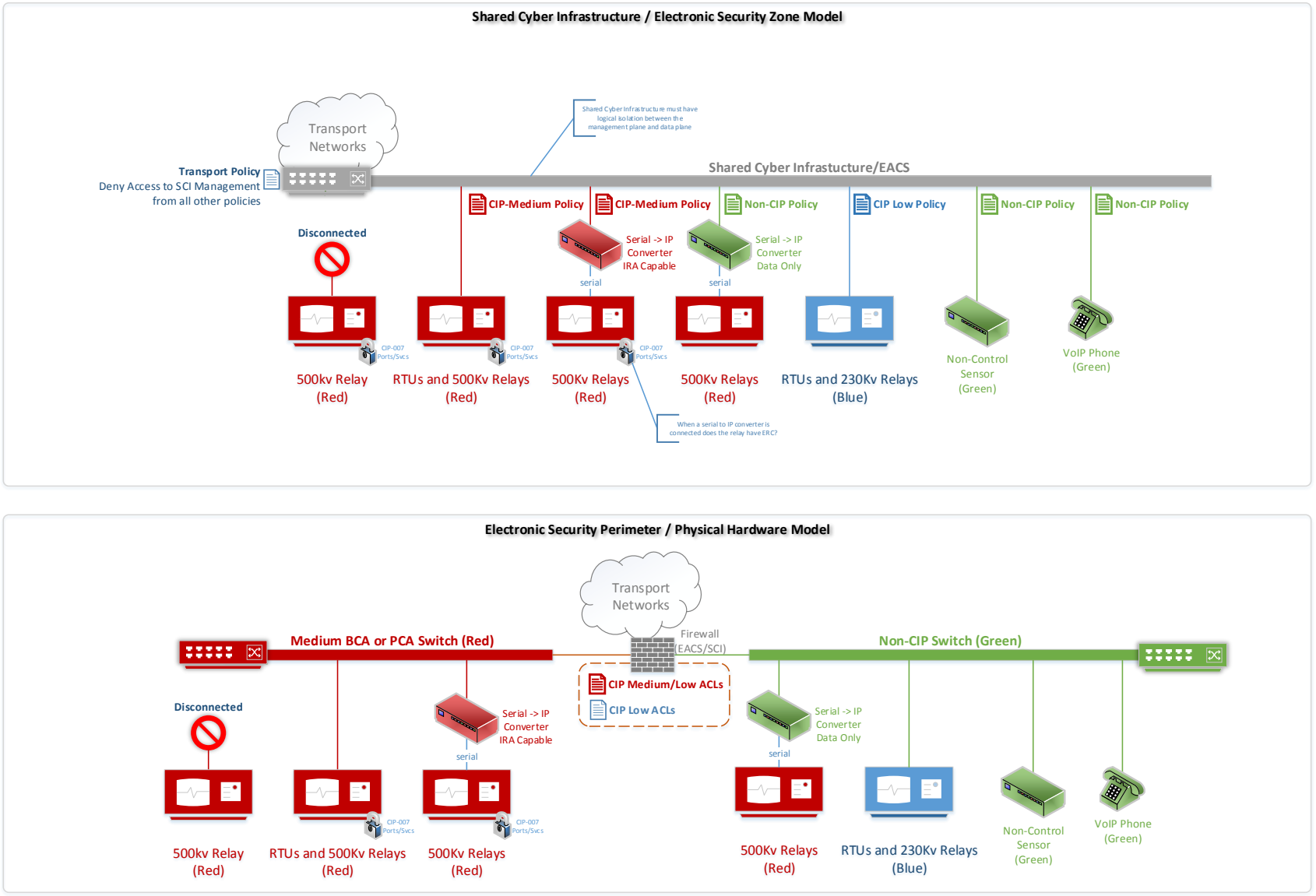
Figure 2 is used to describe substation and plant hybrid virtualization scenarios. It also uses the ESZ concept to secure devices connected to the switch.

Figure 1



This pre-decisional drawing does not reflect a position of NERC or the Standards Drafting Team

Figure 2



This pre-decisional drawing does not reflect a position of NERC or the Standards Drafting Team

Appendix 2 - Technical Rational for Reliability Standard CIP-005-6

This section contains a "cut and paste" of the Technical Rationale components of the former Guidelines and Technical Basis (GTB) as-is of from CIP-005-6 standard to preserve any historical references. Similarly, former GTB content providing compliance guidance can be found in a separate Implementation Guidance document for this standard.

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 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, 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. 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.

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)

E*xplicitly 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 — BES Cyber System Logical Isolation ~~Electronic Security Perimeter(s)~~

2. **Number:** CIP-005-7~~6~~

   Purpose: To protect BES Cyber Systems against compromise by allowing only known and controlled communication to and from the system and logically isolating all other communication. ~~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.~~

3. **Applicability:**

   3.1. Functional Entities: For the purpose of the requirements in this standard ~~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.

   4.1.2.4. 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.**~~**4.1.4.** ~~**Interchange Coordinator or Interchange Authority**~~

~~**4.1.6.**~~**4.1.5.** **Reliability Coordinator**

~~**4.1.7.**~~**4.1.6.** **Transmission Operator**

~~**4.1.8.**~~**4.1.7.** **Transmission Owner**

3.2. Facilities: For the purpose of the requirements in this standard ~~contained herein~~, the following Facilities, systems, and equipment owned by each Responsible Entity in Section 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:

3.2.1.1 Each UFLS or UVLS System that:

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

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

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

3.2.1.3 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.

3.2.1.4 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-005-6:

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

4.2.3.2. Cyber Assets, including third-party owned Cyber Assets, associated with communication networks and data communication links between discrete Electronic Security Perimeters or Electronic Security Zones.

~~4.2.3.2.~~**4.2.3.3.** Cyber Assets, including third-party owned Cyber Assets, associated with communication networks and data communication links used to extend a discrete ESP or ESZ to one or more geographic location.

~~4.2.3.3.~~**4.2.3.4.** 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.~~**4.2.3.5.** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

~~4.2.3.5.~~**4.2.3.6.** 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.

3.3. Effective Date: See Implementation Plan for Project 2016-02~~3~~ (CIP-005-7).

4. Background: Standard CIP-005 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 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 "Applicability Systems" column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002 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 BES Cyber Systems categorized as medium impact according to the CIP-002 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-~~7~~6 Table R1 – Logical Isolation. ~~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-~~7~~6 Table R1 – Logical Isolation ~~Electronic Security Perimeter~~* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-005-6 Table R1 – Electronic Security Perimeter			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.1	High Impact BES Cyber Systems and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI Medium Impact BES Cyber Systems connected to a network via routable protocol and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI	All applicable systems ~~Cyber Assets connected to a network via a routable protocol~~ shall reside within one or more ~~a~~ defined ESPs or ESZs.	An example of evidence may include, but is not limited to, a list of all ESPs or ESZs with all uniquely identifiable applicable systems. ~~Cyber Assets connected via a routable protocol within each ESP.~~

CIP-005-6 Table R1 – Electronic Security Perimeter			
Part	**Applicable Systems**	**Requirements**	**Measures**
~~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.~~
1.2~~3~~	Electronic Security Perimeters and Electronic Security Zones created in Part 1.1. ~~Electronic Access Points for High Impact BES Cyber Systems~~ ~~Electronic Access Points for Medium Impact BES Cyber Systems~~	Require inbound and outbound logical access permissions, including the reason for granting access, and deny all other logical access by default. Excluding time-sensitive protection or control functions between intelligent electronic devices (e.g., communications using protocol IEC TR-61850-90-5 R-GOOSE).	An example of evidence may include, but is not limited to, architectural diagrams that detail how network communication is limited and a list of rules (firewall, access control lists, software defined policies, etc.) that demonstrate that only permitted access is allowed and that each access rule has a documented reason.~~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.~~

CIP-005-6 Table R1 – Electronic Security Perimeter			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.3	Electronic Security Zone or Electronic Security Perimeter that spans more than one geographic location containing: • High Impact BES Cyber Systems • Medium Impact BES Cyber Systems	Protect the confidentiality and integrity of the data traversing communication networks and data communication links used to extend an applicable ESP or ESZ, excluding Real-time Assessment and Real-time monitoring data while being transmitted between Control Centers subject to CIP-012 and excluding time-sensitive protection or control functions between intelligent electronic devices (e.g., communications using protocol IEC TR-61850-90-5 R-GOOSE).	Evidence may include, but is not limited to, architecture documents detailing the methods used to mitigate the risk of unauthorized disclosure. Examples include physical protection and the points where encryption initiates and terminates.

CIP-005-6 Table R1 – Electronic Security Perimeter			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.4	High Impact BES Cyber Systems with Dial-up Connectivity and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI • Medium Impact BES Cyber Systems with Dial-up Connectivity and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI	~~Where technically feasible, p~~Perform authentication when establishing Dial-up Connectivity with applicable systems, per system capability. ~~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-005-6 Table R1 – Electronic Security Perimeter			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.5	High Impact BES Cyber Systems and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI Medium Impact BES Cyber Systems at Control Centers and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI ~~Electronic Access Points for High Impact BES Cyber Systems~~ ~~Electronic Access Points for Medium Impact BES Cyber Systems at Control Cen~~	Have one or more methods for detecting known or suspected malicious routable Internet Protocol (IP) communications to or from ESPs or ESZs. ~~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.

CIP-005-6 Table R1 – Electronic Security Perimeter			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.6	Shared Cyber Infrastructure that hosts High Impact BES Cyber Systems Shared Cyber Infrastructure that hosts Medium Impact BES Cyber Systems	Management systems may only share CPU, memory, or ESZ or ESP with other management systems and the management plane.	Examples of evidence may include, but is not limited to, documentation that includes the configuration of systems that enforce authentication and isolation such as: • Logically isolated out-of-band network infrastructure configuration (ACL, VLAN, VXLAN, MPLS) • Physical isolated out-of-band network for dedicated management interfaces, embedded management interfaces • Compute configuration showing the isolation of the management plane resources (e.g., hypervisor, containers)

R2. Responsible Entity shall implement one or more documented processes that collectively include the applicable requirement parts, per system capability, ~~where technically feasible,~~ in *CIP-005-~~7~~6 Table R2 –Remote Access Management* for all remote access that originates from outside of any of the entities' ESP's or ESZ's containing high or medium impact BES Cyber Systems or associated SCI. *[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-~~7~~6 Table R2 –Remote Access Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-005-6 Table R2 – Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact BES Cyber Systems and their associated: • PCA • SCI Medium Impact BES Cyber Systems with IRA ~~External Routable Connectivity~~ and their associated: • PCA • SCI	~~For all~~ Ensure that Interactive Remote Access is through an Intermediate System that is not inside an applicable ESP or ESZ. ~~, 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	Intermediate Systems associated with High Impact BES Cyber Systems. ~~High Impact BES Cyber Systems and their associated: PCA~~	Protect the confidentiality and integrity of Interactive Remote Access between the client and the Intermediate System. ~~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-005-6 Table R2 – Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
	~~Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:~~ ~~PCA~~ Intermediate Systems associated with Medium Impact BES Cyber Systems.		
2.3	Intermediate Systems associated with High Impact BES Cyber Systems. Intermediate Systems associated with Medium Impact BES Cyber Systems. ~~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 to IS. ~~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.

2.4	High Impact BES Cyber Systems and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI Medium Impact BES Cyber Systems ~~with External Routable Connectivity~~ and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI	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), such as: • 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.
2.5	High Impact BES Cyber Systems and their associated:	Have one or more method(s) to disable active vendor remote access	Examples of evidence may include, but are not limited to, documentation

CIP-005-6 Table R2 – Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
	• PCA • SCI • PACS hosted on SCI • EACS hosted on SCI • Medium Impact BES Cyber Systems ~~with External Routable Connectivity~~ and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI	(including Interactive Remote Access and system-to-system remote access).	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.
2.6	Intermediate Systems that are hosted on SCI and are associated with High Impact BES Cyber Systems. Intermediate Systems that are hosted on SCI and are associated with Medium Impact BES Cyber Systems.	IS may only share CPU, memory, or ESZ or ESP with other IS.	An example of evidence may include, but is not limited to, documentation that includes the following: configuration showing that the CPU and memory can only be shared with other IS.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The ~~[~~applicable ~~entity(ies)]~~systems shall keep data or evidence of Requirement ~~X~~ R1 and Requirement R2 for ~~X~~3 calendar ~~days/months/~~years.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			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-005-6 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 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.	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; OR The Responsible Entity did not have either: one or more method(s) for determining active vendor remote access sessions (including Interactive Remote Access and system-to-system remote access) (2.4); or one or more methods to disable active vendor remote access (including Interactive Remote Access and system-to-system remote access) (2.5).	The Responsible Entity did not implement processes for three of the applicable items for Requirement Parts 2.1 through 2.3; OR 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. Associated Documents~~None.~~

- CIP-005-7 Technical Rationale
- CIP-005-7 Implementation Guidance

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	07/20/17	Modified to address certain directives in FERC Order No. 829.	Revised
6	08/10/17	Adopted by the NERC Board of Trustees.	
6	10/18/2018	FERC Order approving CIP-005-6. Docket No. RM17-13-000.	

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Logical Isolation

2. **Number:** CIP-005-7

   Purpose: To protect BES Cyber Systems against compromise by allowing only known and controlled communication to and from the system and logically isolating all other communication.

3. **Applicability:**

   3.1. Functional Entities: For the purpose of the requirements in this standard, 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.

   4.1.2.4. 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. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

3.2. Facilities: For the purpose of the requirements in this standard, the following Facilities, systems, and equipment owned by each Responsible Entity in Section 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:

3.2.1.1 Each UFLS or UVLS System that:

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

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

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

3.2.1.3 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.

3.2.1.4 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-005-6:

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

4.2.3.2. Cyber Assets, including third-party owned Cyber Assets, associated with communication networks and data

communication links between discrete Electronic Security Perimeters or Electronic Security Zones.

4.2.3.3. Cyber Assets, including third-party owned Cyber Assets, associated with communication networks and data communication links used to extend a discrete ESP or ESZ to one or more geographic location.

4.2.3.4. 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.

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

4.2.3.6. 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.

3.3. Effective Date: See Implementation Plan for Project 2016-02 (CIP-005-7).

4. Background: Standard CIP-005 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 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 "Applicability Systems" column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002 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 BES Cyber Systems categorized as medium impact according to the CIP-002 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.

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-005-7 Table R1 – Logical Isolation. [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-005-7 Table R1 – Logical Isolation* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-005-6 Table R1 – Electronic Security Perimeter			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.1	High Impact BES Cyber Systems and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI Medium Impact BES Cyber Systems connected to a network via routable protocol and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI	All applicable systems shall reside within one or more defined ESPs or ESZs.	An example of evidence may include, but is not limited to, a list of all ESPs or ESZs with all uniquely identifiable applicable systems.

CIP-005-6 Table R1 – Electronic Security Perimeter			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.2	Electronic Security Perimeters and Electronic Security Zones created in Part 1.1.	Require inbound and outbound logical access permissions, including the reason for granting access, and deny all other logical access by default. Excluding time-sensitive protection or control functions between intelligent electronic devices (e.g., communications using protocol IEC TR-61850-90-5 R-GOOSE).	An example of evidence may include, but is not limited to, architectural diagrams that detail how network communication is limited and a list of rules (firewall, access control lists, software defined policies, etc.) that demonstrate that only permitted access is allowed and that each access rule has a documented reason.

CIP-005-6 Table R1 – Electronic Security Perimeter			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.3	Electronic Security Zone or Electronic Security Perimeter that spans more than one geographic location containing: • High Impact BES Cyber Systems • Medium Impact BES Cyber Systems	Protect the confidentiality and integrity of the data traversing communication networks and data communication links used to extend an applicable ESP or ESZ, excluding Real-time Assessment and Real-time monitoring data while being transmitted between Control Centers subject to CIP-012 and excluding time-sensitive protection or control functions between intelligent electronic devices (e.g., communications using protocol IEC TR-61850-90-5 R-GOOSE).	Evidence may include, but is not limited to, architecture documents detailing the methods used to mitigate the risk of unauthorized disclosure. Examples include physical protection and the points where encryption initiates and terminates.

CIP-005-6 Table R1 – Electronic Security Perimeter			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.4	High Impact BES Cyber Systems with Dial-up Connectivity and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI Medium Impact BES Cyber Systems with Dial-up Connectivity and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI	Perform authentication when establishing Dial-up Connectivity with applicable systems, per system capability.	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-005-6 Table R1 – Electronic Security Perimeter			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.5	High Impact BES Cyber Systems and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI Medium Impact BES Cyber Systems at Control Centers and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI	Have one or more methods for detecting known or suspected malicious routable Internet Protocol (IP) communications to or from ESPs or ESZs.	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.

CIP-005-6 Table R1 – Electronic Security Perimeter			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.6	Shared Cyber Infrastructure that hosts High Impact BES Cyber Systems Shared Cyber Infrastructure that hosts Medium Impact BES Cyber Systems	Management systems may only share CPU, memory, or ESZ or ESP with other management systems and the management plane.	Examples of evidence may include, but is not limited to, documentation that includes the configuration of systems that enforce authentication and isolation such as: • Logically isolated out-of-band network infrastructure configuration (ACL, VLAN, VXLAN, MPLS) • Physical isolated out-of-band network for dedicated management interfaces, embedded management interfaces • Compute configuration showing the isolation of the management plane resources (e.g., hypervisor, containers)

R2. Responsible Entity shall implement one or more documented processes that collectively include the applicable requirement parts, per system capability, in *CIP-005-7 Table R2 –Remote Access Management* for all remote access that originates from outside of any of the entities' ESP's or ESZ's containing high or medium impact BES Cyber Systems or associated SCI. *[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-005-7 Table R2 –Remote Access Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-005-6 Table R2 – Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact BES Cyber Systems and their associated: • PCA • SCI Medium Impact BES Cyber Systems with IRA and their associated: • PCA • SCI	Ensure that Interactive Remote Access is through an Intermediate System that is not inside an applicable ESP or ESZ.	Examples of evidence may include, but are not limited to, network, diagrams, or architecture documents.
2.2	Intermediate Systems associated with High Impact BES Cyber Systems. Intermediate Systems associated with Medium Impact BES Cyber Systems.	Protect the confidentiality and integrity of Interactive Remote Access between the client and the Intermediate System.	An example of evidence may include, but is not limited to, architecture documents detailing where encryption initiates and terminates.

CIP-005-6 Table R2 – Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.3	Intermediate Systems associated with High Impact BES Cyber Systems. Intermediate Systems associated with Medium Impact BES Cyber Systems.	Require multi-factor authentication to IS.	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.

2.4	High Impact BES Cyber Systems and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI Medium Impact BES Cyber Systems and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI	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), such as: • 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.
2.5	High Impact BES Cyber Systems and their associated:	Have one or more method(s) to disable active vendor remote access	Examples of evidence may include, but are not limited to, documentation

CIP-005-6 Table R2 – Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
	• PCA • SCI • PACS hosted on SCI • EACS hosted on SCI Medium Impact BES Cyber Systems and their associated: • PCA • SCI • PACS hosted on SCI • EACS hosted on SCI	(including Interactive Remote Access and system-to-system remote access).	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.
2.6	Intermediate Systems that are hosted on SCI and are associated with High Impact BES Cyber Systems. Intermediate Systems that are hosted on SCI and are associated with Medium Impact BES Cyber Systems.	IS may only share CPU, memory, or ESZ or ESP with other IS.	An example of evidence may include, but is not limited to, documentation that includes the following: configuration showing that the CPU and memory can only be shared with other IS.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable systems shall keep data or evidence of Requirement R1 and Requirement R2 for 3 calendar years.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			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-005-6 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 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.	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; OR The Responsible Entity did not have either: one or more method(s) for determining active vendor remote access sessions (including Interactive Remote Access and system-to-system remote access) (2.4); or one or more methods to disable active vendor remote access (including Interactive Remote Access and system-to-system remote access) (2.5).	The Responsible Entity did not implement processes for three of the applicable items for Requirement Parts 2.1 through 2.3; OR 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. Associated Documents

- CIP-005-7 Technical Rationale
- CIP-005-7 Implementation Guidance

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	07/20/17	Modified to address certain directives in FERC Order No. 829.	Revised
6	08/10/17	Adopted by the NERC Board of Trustees.	
6	10/18/2018	FERC Order approving CIP-005-6. Docket No. RM17-13-000.	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CIP Definitions

Project 2016-02 Modifications to CIP Standards

The Project 2016-02 Standard Drafting Team (SDT) is seeking comments on the following new, modified, or retired terms used in the proposed standard. Please note that Project 2016-02 is not proposing changes to Cyber Asset (CA), BES Cyber System (BCS), Electronic Security Perimeter (ESP), and External Routable Connectivity (ERC) definitions to maintain compatibility for non-virtualized systems.

Table 1: Retired, Modified, or Newly Proposed Definitions

NERC Glossary Term	Currently Approved Definition	CIP SDT Proposed New or Revised
BES Cyber Asset (BCA)	A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.	A Cyber Asset or Virtual Cyber Asset; excluding Shared Cyber Infrastructure, that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.

Table 1: Retired, Modified, or Newly Proposed Definitions		
NERC Glossary Term	**Currently Approved Definition**	**CIP SDT Proposed New or Revised**
Shared Cyber Infrastructure (SCI)		Programmable electronic devices whose compute, storage (including network transport), or network resources are shared with one or more Virtual Cyber Assets or that perform logical isolation for an ESZ or ESP. This includes its management systems.
Virtual Cyber Asset (VCA)		A logical instance of an operating system, firmware, or self-contained application hosted on Shared Cyber Infrastructure.

Table 1: Retired, Modified, or Newly Proposed Definitions		
NERC Glossary Term	**Currently Approved Definition**	**CIP SDT Proposed New or Revised**
Transient Cyber Asset (TCA)	A Cyber Asset that is: 1. capable of transmitting or transferring executable code, 2. not included in a BES Cyber System, 3. not a Protected Cyber Asset (PCA) associated with high or medium impact BES Cyber Systems, and 4. directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless including near field or Bluetooth communication) for 30 consecutive calendar days or less to a: • BES Cyber Asset, • network within an Electronic Security Perimeter (ESP) containing high or medium impact BES Cyber Systems, or • PCA associated with high or medium impact BES Cyber Systems. Examples of Transient Cyber Assets include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.	A Cyber Asset or Virtual Cyber Asset that is: 1. capable of transmitting or transferring executable code, 2. not included in a BES Cyber System, 3. not a Protected Cyber Asset (PCA) associated with high or medium impact BES Cyber Systems, and 4. directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless including near field or Bluetooth communication) for 30 consecutive calendar days or less to a: • BES Cyber Asset, • Shared Cyber Infrastructure, • network within an Electronic Security Perimeter (ESP) or Electronic Security Zone containing high or medium impact BES Cyber Systems, or • PCA associated with high or medium impact BES Cyber Systems. Examples of Transient Cyber Assets include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.

Table 1: Retired, Modified, or Newly Proposed Definitions		
NERC Glossary Term	**Currently Approved Definition**	**CIP SDT Proposed New or Revised**
Physical Access Control Systems (PACS)	Cyber Assets that control, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.	Cyber Assets or Virtual Cyber Assets that control~~, alert, or log~~ access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.
Physical Access Monitoring Systems (PAMS)		Cyber Assets or Virtual Cyber Assets that monitor, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.
Protected Cyber Asset (PCA)	One or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP.	Cyber Assets or Virtual Cyber Assets that: • Are connected using a routable protocol within or on an Electronic Security Perimeter that are not part of the highest impact BES Cyber System within the same Electronic Security Perimeter; or • Are within the same Electronic Security Zone that are not part of the highest impact BES Cyber System within the same Electronic Security Zone; or • Share compute resources (CPU or memory) with a BES Cyber System.

Table 1: Retired, Modified, or Newly Proposed Definitions		
NERC Glossary Term	**Currently Approved Definition**	**CIP SDT Proposed New or Revised**
Electronic Access Point (EAP)	A Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.	RETIRED
Electronic Access Control or Monitoring Systems (EACMS)	Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Systems.	RETIRED
Electronic Access Control System (EACS)		Cyber Assets or Virtual Cyber Assets that provide electronic access control to an ESP, ESZ -or BES Cyber System.
Electronic Access Monitoring Systems (EAMS)		Cyber Assets or Virtual Cyber Assets that provide electronic access monitoring of an ESP, ESZ, or BES Cyber System.
Intermediate Systems (IS)	A Cyber Asset or collection of Cyber Assets performing access control to restrict Interactive Remote Access to only authorized users. The Intermediate System must not be located inside the Electronic Security Perimeter.	A type of EACS that is used to restrict Interactive Remote Access.
Electronic Security Zone (ESZ)		A segmented section of a network that contains systems and components to create logical isolation.

Table 1: Retired, Modified, or Newly Proposed Definitions		
NERC Glossary Term	**Currently Approved Definition**	**CIP SDT Proposed New or Revised**
External Routable Connectivity (ERC)	The ability to access a BES Cyber System from a Cyber Asset that is outside of its associated Electronic Security Perimeter via a bi-directional routable protocol connection.	The ability to access a BES Cyber System from a Cyber Asset or Virtual Cyber Asset that is outside of its associated Electronic Security Perimeter or Electronic Security Zone via a bi-directional routable protocol connection.
Interactive Remote Access (IRA)	User-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate System and not located within any of the Responsible Entity's Electronic Security Perimeter(s) or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications.	User-initiated access by a person employing a remote access client.
Physical Security Perimeter (PSP)	The physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled.	The physical border ~~surrounding locations in which BES Cyber Assets, BES Cyber Systems, or Electronic Access Control or Monitoring Systems reside, and for~~ at which access is controlled.

Table 1: Retired, Modified, or Newly Proposed Definitions		
NERC Glossary Term	**Currently Approved Definition**	**CIP SDT Proposed New or Revised**
Removable Media	Storage media that (i) are not Cyber Assets, (ii) are capable of transferring executable code, (iii) can be used to store, copy, move, or access data, and (iv) are directly connected for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP, or a Protected Cyber Asset. Examples include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.	Storage media that (i) are not Cyber Assets, (ii) are capable of transferring executable code, (iii) can be used to store, copy, move, or access data, and (iv) are directly connected for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP or ESZ, ~~or~~ a Protected Cyber Asset, or SCI. ~~Examples include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.~~

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

PRC-024-3 is posted for a 45-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	December 2018
SAR posted for comment	December 2018 – January 2019
Standards Committee accepted the revised SAR	February 2019
45-day formal comment period with ballot	April – May 2019

Anticipated Actions	Date
45-day formal or informal comment period with additional ballot	September – November 2019
10-day final ballot	November 2019
Board adoption	February 2020

A. Introduction

1. **Title:** ~~Generator~~ Frequency and Voltage Protection Settings for Generating Resources

2. **Number:** PRC-024-3

3. **Purpose:** To set ~~generator~~ protection~~,~~ such that generating resource(s) remain connected~~, continuing to support the BES~~ during defined frequency and voltage excursions in support of the Bulk Electric System (BES).~~.~~

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owners that apply protection listed in Section 4.2.1.

   4.1.2. Transmission Owners (in the Quebec Interconnection only) that own a BES generator step-up (GSU) transformer or ~~collector transformer~~main power transformer (MPT) and apply protection listed in Section 4.2.1.

   ~~**4.1.2.**~~**4.1.3.** Planning Coordinators (in the Quebec Interconnection only).

   4.2. Facilities[1]**:**

   4.2.1 Frequency, voltage~~, or~~ and volts per hertz protection (whether provided by relaying or ~~, including frequency or voltage protective~~ functions within associated control systems) ~~that provide tripping or momentary cessation signals to all or part of the generating resource,~~ that respond to electrical signals and: (i) directly trip the generating resource(s); or (ii) provide signals to the generating resource(s) to either trip or cease injecting current; and are applied to the following:

   4.2.1.1 ~~Bulk Electric System (~~BES~~)~~ generating resource(s).

   4.2.1.2 BES GSU transformer(s).

   4.2.1.3 High side of the generator-connected unit auxiliary transformer[2] (UAT) installed on BES generating resource(s).

   4.2.1.4 Individual dispersed power producing resource(s) identified in the BES Definition, Inclusion I4.

   4.2.1.5 Elements ~~utilized in aggregation of~~ that are designed primarily for the delivery of capacity from the individual ~~the~~ dispersed power producing resources identified in the BES Definition,

[1] It is not required to install or activate the protections described in Facilities Section 4.2.

[2] These transformers are variably referred to as station power UAT, or station service transformer(s) used to provide overall auxiliary power to the generating resource(s). This UAT is the transformer connected on the generator bus between the low side of the GSU and the generator terminal.

Inclusion I4, to the point where those resources aggregate to greater than 75 MVA.

4.2.1.6 ~~Collector transformer~~MPT of resource(s) identified in the BES Definition, Inclusion I4.

4.2.2 **Exemptions:** Protection on all auxiliary equipment within the generating Facility.

5. Effective Date: See Implementation Plan for PRC-024-3

B. Requirements and Measures

R1. Each Generator Owner ~~or Transmission Owner~~ shall set its applicable frequency protection[3] in accordance with PRC-024 Attachment 1 ~~-~~such that the applicable protection does not cause the generating resource ~~does not~~to trip or ~~enter momentary cessation~~ cease injecting current during a frequency excursion within the "no trip zone" ~~of PRC-024 Attachment 1, subject~~ with ~~to~~ the following exception: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Applicable frequency protection ~~Generating resource(s)~~ may be set to trip or ~~enter momentary cessation~~ cease injecting current within a portion of the "no trip zone" ~~of PRC-024 Attachment 1~~ for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M1. Each Generator Owner ~~or Transmission Owner~~ shall have evidence that the applicable frequency protection has been set in accordance with Requirement R1, such as dated setting sheets, calibration sheets, calculations, or other documentation.

R2. Each Generator Owner ~~or Transmission Owner~~ shall set its applicable voltage protection[3] in accordance with PRC-024 Attachment 2, such that the applicable protection does not cause the generating resource to ~~does not~~ trip or cease injecting current ~~enter momentary cessation~~ within the "no trip zone" ~~of PRC-024 Attachment 2~~ during a voltage excursion ~~-~~at the high side of the GSU or ~~collector transformer~~MPT, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- If the Transmission Planner allows less stringent voltage protection settings than those required to meet PRC-024 Attachment 2, then the Generator Owner ~~or Transmission Owner~~ may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Applicable voltage protection ~~Generating resource(s)~~ may be set to trip or cease injecting current during a voltage excursion ~~enter momentary cessation~~ within a portion of the "no trip zone" ~~of PRC-024 Attachment 2~~ for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. Each Generator Owner ~~or Transmission Owner~~ shall have evidence that applicable voltage protection has been set in accordance with Requirement R2, such as dated setting sheets, voltage-time boundaries, calibration sheets, coordination plots, dynamic simulation studies, calculations, or other documentation.

[3] Frequency, voltage, and volts per hertz protection (whether provided by relaying or functions within associated control systems) that respond to electrical signals and: (i) directly trip the generating resource(s); or (ii) provide signals to the generating resource(s) to either trip or cease injecting current.

R3. Each Generator Owner ~~or Transmission Owner~~ shall document each known regulatory or equipment limitation[4] that prevents an applicable generating resource(s) with ~~generator~~ frequency or voltage protection from meeting the protection setting criteria in Requirements R1 or R2, including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner ~~or Transmission Owner~~ shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

M3. Each Generator Owner ~~or Transmission Owner~~ shall have evidence that it has documented and communicated any known regulatory or equipment limitations that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3, such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

R4. Each Generator Owner ~~or Transmission Owner~~ shall provide its applicable ~~generator~~ protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated generating resource(s) within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Generator Owner ~~or Transmission Owner~~ shall have evidence that it communicated applicable ~~generator~~ protection settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

[4] Excludes limitations ~~that are~~ caused by the setting capability of the ~~generator~~ frequency and voltage protective relays for the generating resource(s) ~~protection itself~~ but does not exclude limitations originating in the equipment that ~~it~~ the relays protect~~s~~ or frequency and voltage protection imbedded in control systems.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

   1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

   The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   - The Generator Owner ~~or Transmission Owner~~ shall keep data or evidence of Requirements R1 through R4 for 3 years or until the next audit, whichever is longer.
   - If a Generator Owner ~~or Transmission Owner~~ is found non-compliant, the Generator Owner or Transmission Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

   1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Generator Owner ~~or Transmission Owner~~ failed to set its applicable frequency protection so that it does not trip or ~~enter momentary cessation~~ cease injecting current according to Requirement R1.
R2.	N/A	N/A	N/A	The Generator Owner ~~or Transmission Owner~~ failed to set its applicable voltage protection so that it does not trip or cease injecting current~~enter momentary cessation~~ according to Requirement R2.
R3.	The Generator Owner ~~or Transmission Owner~~ documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator	The Generator Owner ~~or Transmission Owner~~ documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator	The Generator Owner ~~or Transmission Owner~~ documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator	The Generator Owner ~~or Transmission Owner~~ failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	The Generator Owner ~~or Transmission Owner~~ failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4.	The Generator Owner ~~or Transmission Owner~~ provided its ~~generator~~ protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner ~~or Transmission Owner~~ provided ~~generator~~ protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner ~~or Transmission Owner~~ provided its ~~generator~~ protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner ~~or Transmission Owner~~ provided ~~generator~~ protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner ~~or Transmission Owner~~ provided its ~~generator~~ protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or ~~Transmission Owner~~ provided ~~generator~~ protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner ~~or Transmission Owner~~ failed to provide its ~~generator~~ protection settings within 150 calendar days of any change to those settings. OR The Generator Owner ~~or Transmission Owner~~ failed to provide ~~generator~~ protection settings within 150 calendar days of a written request.

D. Regional Variances

D.A. Variance for the Quebec Interconnection

~~This Interconnection-wide Variance shall be applicable in the Quebec Interconnection and replaces, in its entirety, continent-wide Requirement R2 with the following:~~

This Variance extends the applicability of Requirements R1, R3, and R4 to Transmission Owners in the Quebec Interconnection that own a BES GSU or MPT and apply protection listed in Section 4.2.1, Facilities. This Variance also replaces Requirement R2 of the continent-wide standard in its entirety and adds a new requirement, Requirement D.A.2, applicable to Planning Coordinators in the Quebec Interconnection.

In Requirements R1, R3, and R4, all references to "Generator Owner" are replaced with "Generator Owner and Transmission Owner."

This Variance replaces continent-wide Requirement R2 in its entirety with the following:

D.A.2. Each Generator Owner ~~or~~ and Transmission Owner shall set its applicable voltage protection[3] in accordance with PRC-024 Attachment 2a, such that the applicable protection does not cause the generating resource ~~does not~~ to trip or cease injecting current ~~enter momentary cessation~~ within the "no trip zone" ~~of PRC-024 Attachment 2a~~ during a voltage excursion at the high side of the GSU or ~~collector transformer~~MPT, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- For newly designated strategic power plants, applicable protections must comply with the high voltage durations for such plants within 48 calendar months of the notification made pursuant to Requirement D.A.5. During this transition period, voltage protections must at least comply with the high voltage durations for "all power plants".
- The generating resource(s) are permitted to be set to trip or to cease injecting current during a voltage excursion bounded by the "no trip zone" of PRC-024 Attachment 2a for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- If the Transmission Planner allows less stringent voltage protection settings than those required to meet PRC-024 Attachment 2a, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.

- ~~Generating resource(s) may trip or enter momentary cessation within a portion of the "no trip zone" of PRC-024 Attachment 2a for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.~~

- Inverter-based resources voltage protection settings may be set to cease injecting current momentarily ~~enter momentary cessation within the "no trip zone" of PRC-024 Attachment 2a~~ during a voltage excursion at the high side of the MPT, bounded by the "no trip zone" of PRC-024 Attachment 2a, under the following conditions:
  - After a minimum delay of 0.022 s, when the positive-sequence voltage exceeds 1.25 per unit (p.u.) Normal operation must resume once the voltage drops back below 1.25 p.u at the high side of the MPT.
  - After a minimum delay of 0.022 s, when the phase-to-ground root mean square (RMS) voltages exceeds 1.4 p.u., as measured at generator terminals, on one or multiple phases. Normal operation must resume once the positive-sequence voltage drops back below the 1.25 p.u. at the high side of the MPT.

M.D.A.2. Each Generator Owner ~~or~~ and Transmission Owner shall have evidence that applicable voltage protection has been set in accordance with Requirement R2, such as dated setting sheets, voltage-time boundaries, calibration sheets, coordination plots, dynamic simulation studies, calculations, or other documentation.

This Variance adds the following Requirement:

D.A.5 Each Planning Coordinator shall designate, at least once every five calendar years, the strategic power plants that must comply with Attachment 2a and notify, within 30 calendar days of its designation, each Generator Owner or Transmission Owner that owns facilities[5] in the strategic power plants. *[Violation Risk Factor: High] [Time Horizon: Long-term planning]*

M.D.A.5 Each Planning Coordinator shall have evidence that it designated, at least once every five calendar years, strategic power plants in accordance with Requirement D.A.5, Part 5 and shall have dated evidence that each Generator Owner or Transmission Owner has been notified in accordance with Requirement D.A.5, part 5.2. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

[5] Facilities in the strategic power plants include facilities from the generator up to and including the MPT or GSU.

Violation Severity Levels

This Variance adds a VSL for D.A.5. and modifies the VSL for R2 as follows:

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.A.2.	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to set its applicable voltage protection so that it does not trip or cease injecting current in accordance with Requirement D.A.2. OR The Generator Owner or Transmission Owner set its applicable voltage protection in accordance with Requirement D.A.2 but, for strategic power plants, failed to do so within 48 months of notification.
D.A.5.	N/A	The Planning Coordinator designated strategic power plants at least once every five calendar years but notified each Generator Owner or	The Planning Coordinator designated strategic power plants at least once every five calendar years but notified each Generator Owner or	The Planning Coordinator failed to designate, at least once every five years, the strategic

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		Transmission Owner that owns facilities in the strategic power plants between 31 days and 45 days after its designation.	Transmission Owner that owns facilities in the strategic power plants between 46 days and 60 days after its designation.	power plants that must comply with Attachment 2a. OR The Planning Coordinator failed to notify, each Generator Owner or Transmission Owner that owns facilities in the strategic power plants or notified them more than 60 days after the its designation.

E. Associated Documents

Implementation Plan

~~Industry Recommendation I – Loss of Solar Resources during Transmission Disturbances Due to Inverter Settings~~

~~Industry Recommendation II – Loss of Solar Resources during Transmission Disturbances due to Inverter Settings~~

~~Blue Cut Fire Disturbance~~

~~Canyon 2 Fire Disturbance~~

~~"Protective Relaying For Power Generation Systems", Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald~~

~~"IEEE C37.102 IEEE Guide for AC Generator Protection"~~

~~"IEEE C50.13 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"~~

~~"IEEE C37.106 IEEE Guide for Abnormal Frequency Protection for Power Generating Plants"~~

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	
1	March 20, 2014	FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)	
2	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 29, 2015	FERC Letter Order in Docket No. RD15-3-000 approving PRC-024-2	Modifications to adjust the applicability to owners of dispersed generation resources.

Attachment 1

(Frequency No Trip ~~Boundary~~ Boundaries by Interconnection[6])

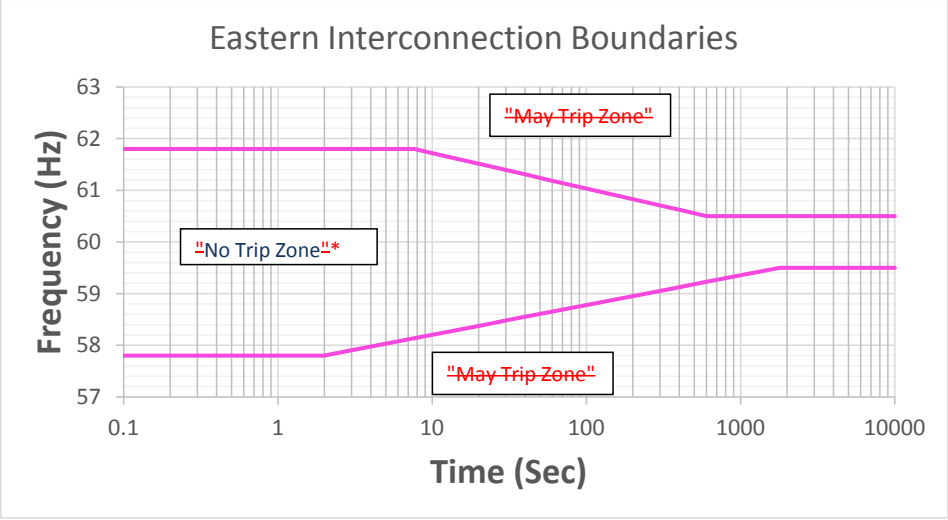


Figure 1

**** The area outside the "No Trip Zone" is not a "Must Trip Zone."***

Frequency Boundary Data Points – Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.8	Instantaneous[7] ~~0.10~~	≤57.8	Instantaneous[7] ~~0.10~~
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Table 1

[6] The figures do not visually represent the "no trip zone" boundaries before 0.1 seconds and after 10,000 seconds. The Frequency Boundary Data Points Table defines the entirety of the "no trip zone" boundaries.

[7] Frequency is calculated over a window of time. While the frequency boundaries include the option to trip instantaneously for frequencies outside the specified range, this calculation should occur over a time window. Typical window/filtering lengths are three to six cycles (50 – 100 milliseconds). Instantaneous trip settings based on instantaneously calculated frequency measurement is not permissible.

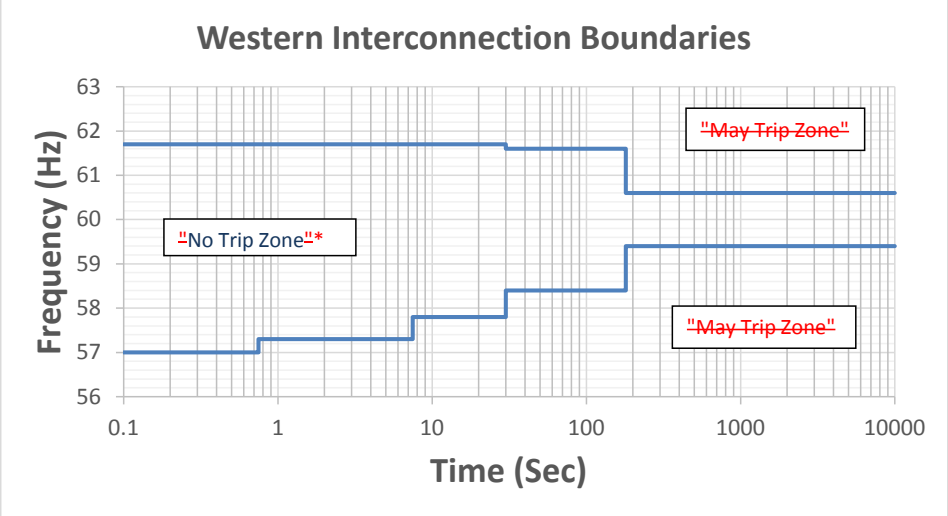


Figure 2

*** The area outside the "No Trip Zone" is not a "Must Trip Zone."**

Frequency Boundary Data Points – Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.7	Instantaneous[7] 0.10	≤57.0	Instantaneous[7] 0.10
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

Table 2

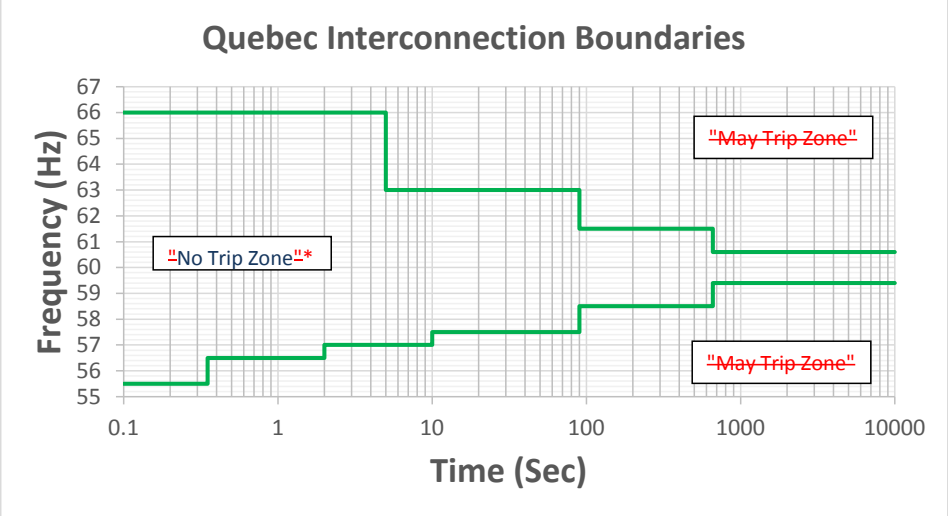


Figure 3

*** The area outside the "No Trip Zone" is not a "Must Trip Zone."**

Frequency Boundary Data Points – Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (Sec)
>66.0	Instantaneous[7] 0.10	<55.5	Instantaneous[7] 0.10
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

Table 3

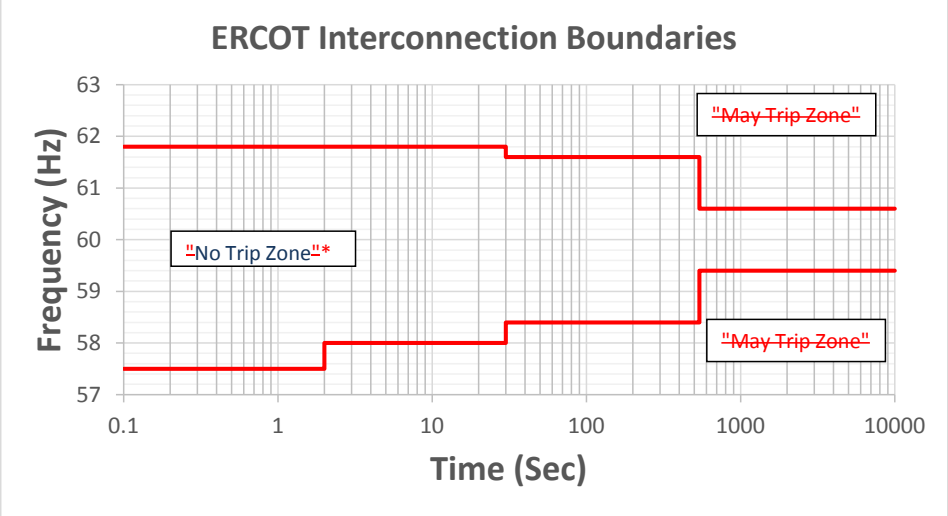


Figure 4

*** The area outside the "No Trip Zone" is not a "Must Trip Zone."**

Frequency Boundary Data Points – ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.8	Instantaneous[7] ~~0.10~~	≤57.5	Instantaneous[7] ~~0.10~~
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

Table 4

PRC-024 — Attachment 2

(Voltage No-Trip Boundaries ~~Boundary~~ – Eastern, Western, and ERCOT Interconnections)

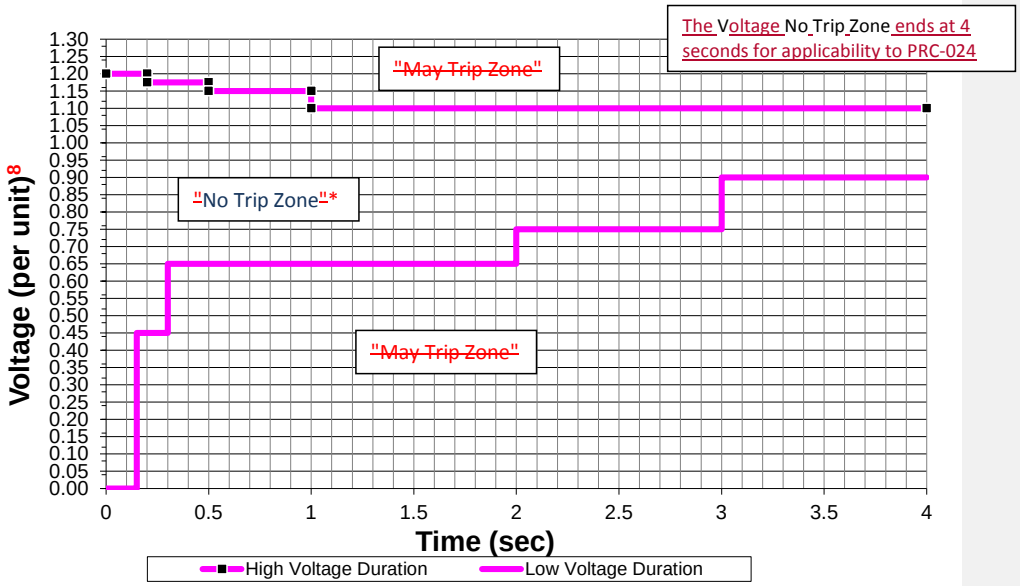


Figure 1

Voltage Boundary Data Points

High Voltage Duration		Low Voltage Duration	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
≥1.200	0.00	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00
<1.10	4.00	≥ 0.90	4.00

Table 1

[7] ~~Voltage~~ [8] Voltage at the high-side of the GSU or ~~collector transformer~~MPT.

Attachment 2: Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections

Boundary Details:

1. Unless otherwise specified by the Transmission Planner, the~~The~~ per unit voltage base for these boundaries is the nominal transmission system ~~operating~~ voltage (e.g., 100 kV, 115~~-~~kV, 138 kV, 161 kV, ~~-~~230 kV~~,~~ 345 kV, 400 kV, 500 kV, 765 kV,~~-~~ etc.).

~~2. The boundaries apply to voltage excursions regardless of the type of initiating event.~~

~~3.~~2. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.

~~4.~~3. ~~The boundaries assume a system frequency of 60 Hertz.~~ When evaluating volts per hertz protection, either assume a system frequency of 60 Hertz or the magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.

~~5.~~4. Voltages in the boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase per unit voltage.

~~6.~~5. For applicability to PRC-024, the ~~The~~ "no trip zone" ends at 4 seconds.

Evaluating Protection Settings:

The voltage values in the Attachment 2 voltage boundaries are voltages at the high side of the GSU/MPT. For generating resources with multiple stages of step up to reach interconnecting voltage, this is the high side of the transformer with a low side below 100 kV and a high side 100kV or above**.** When evaluating protection settings, consider the voltage differences between where the protection is measuring voltage and the high side of the GSU/MPT. A steady state calculation or dynamic simulation may be used.

If using a steady state calculation or dynamic simulation, use the following conditions when evaluating protection settings:

a. The most probable real and reactive loading conditions for the unit under study.
b. All installed generating plant reactive support (e.g., static VAR compensators, synchronous condensers, capacitors) equipment is available and operating normally.
c. Account for the actual tap settings of transformers between the generator terminals and the high side of the GSU/MPT.
d. For dynamic simulations, the automatic voltage regulator is in automatic voltage control mode with associated limiters in service.

~~1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection setting calculations on the static case for steady state initial conditions:~~

~~a. All of the units connected to the same transformer are online and operating.~~

~~b. All of the units are at full nameplate real-power output.~~

~~c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.~~

~~d. The automatic voltage regulator is in automatic voltage control mode.~~

~~2. Evaluate voltage protection settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.~~

~~3. Evaluate voltage protection settings accounting for the actual tap settings of transformers between the generator terminals and the high side of the GSU or collector transformer.~~

PRC-024— Attachment 2a

(Voltage No-Trip Boundaries – Quebec Interconnection)

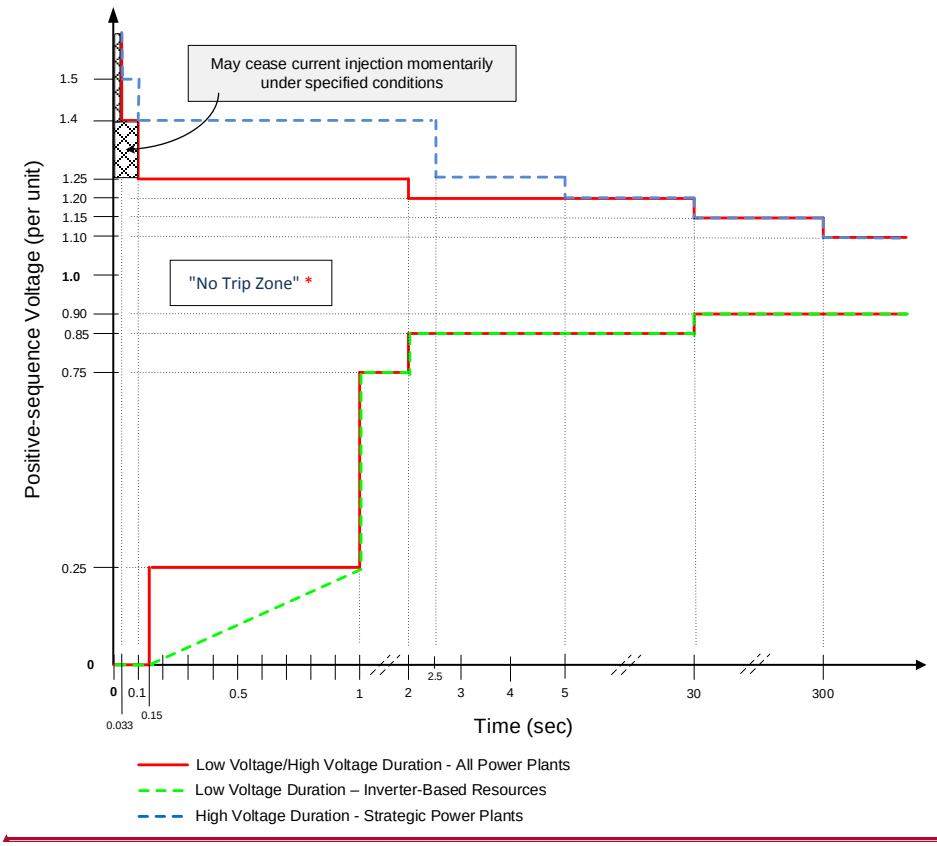


Figure 1

**** The area outside the "No Trip Zone" is not a "Must Trip Zone"***

Field Code Changed

Voltage Boundary Data Points – Quebec Interconnection

High Voltage Duration for all Power Plants		High Voltage Duration for strategic[1] Power Plants	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
---	---	>1.50	0.033
>1.40	0.033	>1.40	0.10
>1.25	0.10	>1.25	2.50
>1.20	2.00	>1.20	5.00
>1.15	30	>1.15	30
>1.10	300	>1.10	300
≤1.10	continuous	≤1.10	continuous

Table 1

Voltage Boundary Data Points – Quebec Interconnection

Low Voltage Duration for all Power Plants		Low Voltage Duration for Inverter-Based Resources	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
<0.25	0.15	<0.25	3.4*V(pu)+0.15
<0.75	1.00	<0.75	1.00
<0.85	2.00	<0.85	2.00
<0.90	30	<0.90	30
≥0.90	continuous	≥0.90	continuous

Table 2

[1] ~~Power Plants designated by the Transmission Planner for protecting the integrity of Transmission System equipment.~~

Attachment 2a: Voltage Boundary Clarifications – Quebec Interconnection

Boundary Details:

1. The per unit voltage base for these boundaries is the nominal operating voltage (e.g., 120 ~~115~~ kV, ~~138~~ 161 kV, 230 kV, ~~345~~ 315 kV, ~~500~~ 735 kV, etc.).

~~2. The boundaries apply to voltage excursions regardless of the type of initiating event.~~

~~3.~~2. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.

~~4.~~3. ~~The boundaries assume a system frequency of 60 Hertz.~~ When evaluating volts per hertz protection, either assume a system frequency of 60 Hertz or the magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.

~~5.~~4. Voltages in the Quebec Interconnection boundaries assume positive-sequence values.

Evaluating Protection Settings:

~~1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection setting calculations on the static case for steady state initial conditions:~~

~~a. All of the units connected to the same transformer are online and operating.~~

~~b. All of the units are at full nameplate real-power output.~~

~~c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.~~

~~d. The automatic voltage regulator is in automatic voltage control mode.~~

~~2. Evaluate voltage protection settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.~~

~~3. Evaluate voltage protection settings accounting for the actual tap settings of transformers between the generator terminals and the high side of the GSU or collector transformer.~~

The voltage values in the Attachment 2a voltage boundaries are voltages at the high side of the GSU/MPT. For generating resources with multiple stages of step up to reach interconnecting voltage, this is the high side of the transformer that connects to the interconnecting voltage. When evaluating protection settings, consider the voltage differences between where the protection is measuring voltage and the high side of the GSU/MPT. A steady state calculation or dynamic simulation may be used.

Formatted: Space After: 0 pt, Don't adjust space between Latin and Asian text, Don't adjust space between Asian text and numbers

If using a steady state calculation or dynamic simulation, use the following conditions when evaluating protection settings:

a. The most probable real and reactive loading conditions for the unit under study.
b. All installed generating plant reactive support (e.g., static VAR compensators, synchronous condensers, capacitors) equipment is available and operating normally.
c. Account for the actual tap settings of transformers between the generator terminals and the high side of the GSU/MPT.
d. For dynamic simulations, the automatic voltage regulator is in automatic voltage control mode with associated limiters in service.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2018-04 Modifications to PRC-024-2
Reliability Standard PRC-024-3

Applicable Standard

- Reliability Standard PRC-024-3 – ~~Generator~~ Frequency and Voltage Protection Settings for Generating Resources

Requested Retirement

- Reliability Standard PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings

Prerequisite Standard(s)

- None

Applicable Entities

- Generator Owners that apply protection listed in Section 4.2.1.
- Transmission Owners (in the Quebec Interconnection only) that own a BES generator step-up (GSU) transformer or main power transformer (MPT) and apply protection listed in Section 4.2.1.
- Planning Coordinators (in the Quebec Interconnection only).
- ~~Generator Owners that apply protection listed in Section 4.2.1.~~
- ~~Transmission Owners that own a BES generator step-up transformer or collector transformer and apply protection listed in Section 4.2.1.~~

Background

Reliability Standard PRC-024-3 contains a series of revisions and clarifications intended to help ensure that inverter-based resources respond to grid disturbances in a manner that contributes to the reliable operation of the Bulk-Power System.

The standard was revised to address recommendations of the NERC Inverter-Based Resource Performance Task Force. These recommendations were developed in response to the findings and recommendations of the NERC and WECC analysis of the Blue Cut Fire and Canyon 2 Fire disturbances in southern California.

In addition, the standard includes a Regional Variance for the Quebec Interconnection and related revisions to clarify the applicability of the standard in that Interconnection.

~~Address issues related to IBRs dropping offline~~
~~On November 27, 2018, the NERC Operating Committee (OC) and Planning Committee (PC) submitted a Standard Authorization Request (SAR) prepared by the Inverter-Based Resource Performance Task Force (IRPTF), which reports to the OC and PC. Project 2018-04 addresses this SAR.~~

~~In 2017, the OC and PC convened the IRPTF shortly after it became clear that inverter-based generation was dropping off-line during normally cleared Bulk Power System (BPS) line faults. The NERC IRPTF supported NERC and WECC staff in the analysis of the Blue Cut Fire and Canyon 2 Fire disturbances in southern California. From the key findings and recommendations in the reports on the analysis, the IRPTF (as a stakeholder group of industry experts) developed recommended performance characteristics from inverter-based resources connected to the BPS.~~

~~Based off the disturbance analyses and development of the PRC-024-2 Gaps Whitepaper, the IRPTF identified potential modifications to PRC-024-2 to help ensure that inverter-based generator owners, operators, developers, and equipment manufacturers understand the intent of the standard in order for their plants respond to grid disturbances in a manner that contributes to the reliable operation of the BPS.~~

~~Supplemental SAR~~

General Considerations

This Implementation Plan is intended to provide applicable entities with sufficient time to evaluate settings, make changes for applicable equipment, and purchase necessary equipment, if necessary. Setting changes and equipment installations are typically completed during generating Facility outages, which may be scheduled in up to twenty-four (24) month intervals. ~~includes an effective date as well as phased-in compliance dates. As detailed below, there are two compliance dates: one for Generator Owners, and one for Transmission Owners.~~

Effective Date

Reliability Standard PRC-024-3

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 twenty-four (24) ~~eighteen (18)~~ months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) ~~eighteen (18)~~ 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 Applicable Generator Owners**~~

~~Applicable Generator Owners shall comply with all Requirements upon the effective date of Reliability Standard PRC-024-3.~~

Retirement Date

Reliability Standard PRC-024-2

Reliability Standard PRC-024-2 shall be retired immediately prior to the effective date of Reliability Standard PRC-024-3 in the particular jurisdiction in which the revised standard is becoming effective.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-04 Modifications to PRC-024-2 ~~April~~ September 2019

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard PRC-024-3. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

Justification for PRC-024-3 VRFs and VSLs

VRF Justification for PRC-024-3, Requirement R1

The VRF did not change from the previously FERC-approved PRC-024-2 Reliability Standard.

VSL Justification for PRC-024-3, Requirement R1

The SDT only made changes to conform the Requirement R1 VSL to the revised Requirement R1 language. The SDT retained the binary structure of the VSL, which is consistent with both the PRC-024-2 and PRC-024-1 VSLs. As a result, the justification for the Commission-approved PRC-024-1 Requirement R1 VSL supports the justification for the proposed PRC-024-3, Requirement R1 VSL.

VRF Justification for PRC-024-3, Requirement R2

The VRF did not change from the previously FERC-approved PRC-024-2 Reliability Standard.

VSL Justification for PRC-024-3, Requirement R2

The SDT only made changes to conform the Requirement R2 VSL to the revised Requirement R2 language. The SDT retained the binary structure of the VSL, which is consistent with both the PRC-024-2 and PRC-024-1 VSLs. As a result, the justification for the Commission-approved PRC-024-1 Requirement R2 VSL supports the justification for the proposed PRC-024-3, Requirement R2 VSL.

VRF Justification for PRC-024-3, Requirement R3

The VRF did not change from the previously FERC-approved PRC-024-2 Reliability Standard.

VSL Justification for PRC-024-3, Requirement R3

~~The SDT only revised the Requirement R3 VSL to add Transmission Owner.~~ The SDT only revised the Requirement R4 VSL to remove the word "generator" to encompass all protection as defined in Section 4.2, Facilities. -The SDT retained the existing levels of the VSLs, which is consistent with both the PRC-024-2 and PRC-024-1 VSLs. As a result, the justification for the Commission-approved PRC-024-1 Requirement R3 VSL supports the justification for the proposed PRC-024-3, Requirement R3 VSL.

VRF Justification for PRC-024-3, Requirement R4

The VRF did not change from the previously FERC-approved PRC-024-2 Reliability Standard.

VSL Justification for PRC-024-3, Requirement R4

The SDT only revised the Requirement R4 VSL to remove the word "generator" to encompass all protection as defined in Section 4.2, Facilities.~~ add Transmission Owner.~~ The SDT retained the existing levels of the VSLs, which is consistent with both the PRC-024-2 and PRC-

024-1 VSLs. As a result, the justification for the Commission-approved PRC-024-1 Requirement R4 VSL supports the justification for the proposed PRC-024-3, Requirement R4 VSL.

VRF Justification for PRC-024-3, Requirement D.A.2.
The SDT made changes to conform the Requirement D.A.2. VSL to the revised Requirement 2 language with the addition of different no trip voltage boundaries based on power plant type as designated by the Planning Coordinator.

VSL Justification for PRC-024-3, Requirement D.A.2.
The SDT only made changes to conform Requirement D.A.2. with the Requirement R2 VSL as well as to add that newly designated strategic power plants have no less than 48 months to set their protection in accordance with the strategic power plant voltage boundaries in Attachment 2a. The SDT retained the binary structure of the VSL, which is consistent with both the PRC-024-2 and PRC-024-1 VSLs. As a result, the justification for the Commission-approved PRC-024-1 Requirement R2 VSL supports the justification for the proposed PRC-024-3, Requirement D.A.2. VSL.

VRF Justification for PRC-024-3, Requirement D.A.5.
The VRF for Requirement D.A.5. is Medium, given that is unlikely to lead to Bulk Electric System instability, separation, or cascading failures if violated. This is consistent with Requirements R1, R2, and D.A.2.

VSL Justification for PRC-024-3, Requirement D.A.5.
Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified. Proposed VSL's are based on a single violation and not a cumulative violation methodology.

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 proposed standard for formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 20, 2019
SAR posted for comment	February 25 – March 27, 2019

Anticipated Actions	Date
45-day formal comment period with ballot	July – September 2019
45-day formal comment period with additional ballot	October – December 2019
45-day formal comment period with second additional ballot	January – March 2020
10-day final ballot	April 2020
Board adoption	May 2020

A. Introduction

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events

2. **Number:** TPL-007-~~3~~4

3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.2. Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.3. Transmission Owner who owns a Facility or Facilities specified in 4.2; and

   4.1.4. Generator Owner who owns a Facility or Facilities specified in 4.2.

   4.2. Facilities:

   4.2.1. Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

5. **Effective Date:** See Implementation Plan for TPL-007-~~3~~4.

~~6.~~ **Background:** During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

~~7.~~6. ~~The only difference between TPL-007-3 and TPL-007-2 is that TPL-007-3 adds a Canadian Variance to address regulatory practices/processes within Canadian jurisdictions and to allow the use of Canadian-specific data and research to define and implement alternative GMD event(s) that achieve at least an equivalent reliability objective of that in TPL-007-2.~~

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data in accordance with Requirement R1.

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Benchmark GMD Vulnerability Assessment(s)

R4. Each responsible entity, as determined in Requirement R1, shall complete a benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This benchmark GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1.

4.3. The benchmark GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.

4.3.1. If a recipient of the benchmark GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its benchmark GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its benchmark GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later, as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its benchmark GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the benchmark thermal impact assessment of transformers specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R6. Each Transmission Owner and Generator Owner shall conduct a benchmark thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The benchmark thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its benchmark thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

R7. Each responsible entity, as determined in Requirement R1, that concludes through the benchmark GMD Vulnerability Assessment conducted in Requirement R4 that their System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1, shall develop a Corrective

Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be developed within one year of completion of the benchmark GMD Vulnerability Assessment.

7.3. Include a timetable, subject to ~~revision by the responsible entity~~ ERO approval for any extension sought under ~~in~~ Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be submitted to the ERO with a request for extension ~~revised~~ if ~~situations beyond the control of~~ the responsible entity is unable to ~~determined in Requirement R1 prevent~~ implement~~ation of~~ the CAP within the timetable ~~for implementation~~provided in Part 7.3. The submitted ~~revised~~ CAP shall document the following~~, and be updated at least once every 12 calendar months until implemented~~:

~~**7.4.1.**~~ Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

~~**7.4.2.**~~**7.4.1.** ~~Description of the original CAP, and any previous changes to the CAP, with the associated timetable(s) for implementing the selected actions in Part 7.1; and~~

7.4.2. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable; and~~,~~

7.4.3. ~~and the~~ U~~u~~pdated timetable for implementing the selected actions in Part 7.1.

7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

7.5.1. If a recipient of the CAP provides documented comments on the CAP ~~results~~, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, ~~-~~that it submitted a request for extension to the ERO if ~~has revised its CAP if situations beyond~~ the responsible entity~~'s~~ is unable to ~~control prevent~~ implement~~ation of~~ the CAP within the timetable provided in Part 7.3~~specified~~. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Supplemental GMD Vulnerability Assessment(s)

R8. Each responsible entity, as determined in Requirement R1, shall complete a supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This supplemental GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. The study or studies shall include the following conditions:

8.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

8.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

8.2. The study or studies shall be conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event contained in Table 1.

~~**8.3.** If the analysis concludes there is Cascading caused by the supplemental GMD event described in Attachment 1, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.~~

~~8.4.~~8.3. The supplemental GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.

~~8.4.1.~~8.3.1. If a recipient of the supplemental GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its supplemental GMD Vulnerability Assessment meeting all of the requirements in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its supplemental GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later, as specified in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its supplemental GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R9. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the supplemental thermal impact assessment of transformers specified in Requirement R10 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

9.1. The maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

9.2. The effective GIC time series, GIC(t), calculated using the supplemental GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1.

M9. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R9, Part 9.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R10. Each Transmission Owner and Generator Owner shall conduct a supplemental thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater. The supplemental thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

10.1. Be based on the effective GIC flow information provided in Requirement R9;

10.2. Document assumptions used in the analysis;

10.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

10.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.

M10. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its supplemental thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its supplemental thermal impact assessment to the responsible entities as specified in Requirement R10.

R11. Each responsible entity, as determined in Requirement R1, that concludes through the supplemental GMD Vulnerability Assessment conducted in Requirement R8 that their System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1, shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

11.1. 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 Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

11.2. Be developed within one year of completion of the supplemental GMD Vulnerability Assessment.

11.3. Include a timetable, subject to ERO approval for any extension sought under Part 11.4, for implementing the selected actions from Part 11.1. The timetable shall:

11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

11.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

11.4. Be submitted to the ERO with a request for extension if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. The submitted CAP shall document the following:

11.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

11.4.2. Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures, if applicable; and

11.4.3. Updated timetable for implementing the selected actions in Part 11.1.

11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it submitted a request for extension to the ERO if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

GMD Measurement Data Processes

~~R11.~~R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator~~'~~'s planning area or other part of the system included in the Planning Coordinator~~'~~'s GIC System model. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~M10.~~M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement R12~~1~~.

~~R12.~~R13. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~M11.~~M13. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator's planning area in accordance with Requirement R13~~2~~.

~~B.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- For Requirements R1, R2, R3, R5, R6, R9, and R10, each responsible entity shall retain documentation as evidence for five years.
- For Requirements R4 and R8, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.

- For Requirement R7 and R11, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.
- For Requirements R1~~2~~1 and R1~~3~~2, each responsible entity shall retain documentation as evidence for three years.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Table 1: Steady State Planning GMD Event

Steady State:

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.
b. Generation loss is acceptable as a consequence of the steady state planning GMD events.
c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
Benchmark GMD Event – GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]
Supplemental GMD Event – GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes	Yes

Table 1: Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the benchmark and supplemental planning events are described in Attachment 1.
3. Load loss as a result of manual or automatic Load shedding (e.g., UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard.
R2.	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the studies	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the studies

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			needed to complete benchmark and supplemental GMD Vulnerability Assessments.	needed to complete benchmark and supplemental GMD Vulnerability Assessments.
R3.	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1 as required.
R4.	The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last benchmark GMD Vulnerability Assessment.	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 72 calendar months since the last benchmark

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		last benchmark GMD Vulnerability Assessment.	last benchmark GMD Vulnerability Assessment.	GMD Vulnerability Assessment; OR The responsible entity does not have a completed benchmark GMD Vulnerability Assessment.
R5.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R6.	The responsible entity failed to conduct a benchmark thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the	jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the	applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		required elements as listed in Requirement R6, Parts 6.1 through 6.3.	required elements as listed in Requirement R6, Parts 6.1 through 6.3.	in Requirement R6, Parts 6.1 through 6.3.
R7.	The responsible entity~~'~~s Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity~~'~~s Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity~~'~~s Corrective Action Plan failed to comply with three of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity~~'~~s Corrective Action Plan failed to comply with four or more of the elements in Requirement R7, Parts 7.1 through 7.5; OR The responsible entity did not develop ~~have~~ a Corrective Action Plan as required by Requirement R7.
R8.	~~The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R8, Parts 8.1 through 8.4;~~ ~~OR~~ The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity~~'~~s completed supplemental GMD Vulnerability Assessment failed to satisfy ~~two~~ one of the elements listed in Requirement R8, Parts 8.1 through 8.34; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity~~'~~s completed supplemental GMD Vulnerability Assessment failed to satisfy ~~three~~ two of the elements listed in Requirement R8, Parts 8.1 through 8.34; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity~~'~~s completed supplemental GMD Vulnerability Assessment failed to satisfy three~~four~~ of the elements listed in Requirement R8, Parts 8.1 through 8.34; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment.	than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD Vulnerability Assessment.	than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.
R9.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R10.	The responsible entity failed to conduct a supplemental thermal impact assessment for 5% or less or one of its	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 5% up to (and	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 10% up to	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 15% or more

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.	including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1 OR	(and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR	than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		The responsible entity failed to include one of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include two of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include three of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.
R11.	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R11, Parts 11.1 through 11.5. ~~N/A~~	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R11, Parts 11.1 through 11.5. ~~N/A~~	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R11, Parts 11.1 through 11.5. ~~N/A~~	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R11, Parts 11.1 through 11.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R11. ~~The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System Model.~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R12.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System Model. ~~The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.~~
R13.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

~~C.~~D. Regional Variances

D.A. Regional Variance for Canadian Jurisdictions

This Variance shall be applicable in those Canadian jurisdictions where the Variance has been approved for use by the applicable governmental authority or has otherwise become effective in the jurisdiction.

This variance replaces ~~A~~all references to "Attachment 1" in the standard ~~are replaced~~ with "Attachment 1 or Attachment 1-CAN."

In addition, this Variance replaces Requirement R7, Part 7.3 through Part 7.5 and Requirement R11, Part 11.3 through Part 11.5 with the following:

D.A.7.3. Include a timetable, subject to revision by the responsible entity in Part D.A.7.4, for implementing the selected actions from Part 7.1. The timetable shall:

D.A.7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP- or receipt of regulatory approvals, if required; and

D.A.7.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.7.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.7.3. The revised CAP shall document the following:

D.A.7.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

D.A.7.4.2 Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable; and

D.A.7.4.3 Updated timetable for implementing the selected actions in Part 7.1.

D.A.7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision.

D.A.7.5.1 If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

D.A.11.3.–Include a timetable, subject to revision by the responsible entity in Part D.A.11.4, for implementing the selected actions from Part 11.1. The timetable shall:

D.A.11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP or receipt of regulatory approvals, if required; and

D.A.11.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.11.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.11.3. The revised CAP shall document the following:

D.A.11.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

D.A.11.4.2. Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures if applicable; and

D.A.11.4.3. Updated timetable for implementing the selected actions in Part 11.1.

D.A.11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision.

D.A.11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

~~D.~~E. Associated Documents

Attachment 1

Attachment 1-CAN

Version History

Version	Date	Action	Change Tracking
1	December 17, 2014	Adopted by the NERC Board of Trustees	New
2	November 9, 2017	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order No. 830.
2	November 25, 2018	FERC Order issued approving TPL-007-2. Docket No. RM18-8-000	
3	February 7, 2019	Adopted by the NERC Board of Trustees	Canadian Variance
4	TBD	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order. 851

Attachment 1

Calculating Geoelectric Fields for the Benchmark and Supplemental GMD Events

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveform to facilitate time-domain analysis of GMD impact on equipment.

The supplemental GMD event is composed of similar elements as described above, except (1) the reference peak geoelectric field amplitude is 12 V/km over a localized area; and (2) the geomagnetic field time series or waveform includes a local enhancement in the waveform.[2]

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km for the benchmark GMD event (1) or 12 V/km for the supplemental GMD event (2) using the following relationships:

$$E_{peak} = 8 \times \alpha \times \beta_{b} \, (V/km) \quad (1)$$

$$E_{peak} = 12 \times \alpha \times \beta_{s} \, (V/km) \quad (2)$$

where, α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure. Subscripts *b* and *s* for the β scaling factor denote association with the benchmark or supplemental GMD events, respectively.

Scaling the Geomagnetic Field

The benchmark and supplemental GMD events are defined for geomagnetic latitude of 60° and must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression:

$$\alpha = 0.001 \times e^{(0.115 \times L)} \quad (3)$$

where, L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1$.

[1] The Benchmark Geomagnetic Disturbance Event Description, May 2016 is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/Stand/TPL0071RD/Benchmark_clean_May12_complete.pdf.

[2] The extent of local enhancements is on the order of 100 km in North-South (latitude) direction but longer in East-West (longitude) direction. The local enhancement in the geomagnetic field occurs over the time period of 2-5 minutes. Additional information is available in the Supplemental Geomagnetic Disturbance Event Description, October 2017 white paper on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

Table 2: Geomagnetic Field Scaling Factors for the Benchmark and Supplemental GMD Events

Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either:

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[3] or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (3) or Table 2, β is applied to the reference geoelectric field using equation (1 or 2, as applicable) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessments. When a ground conductivity model is not available, the planning entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

[3] Available at the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[4] The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta_b = E/8 \text{ for the benchmark GMD event} \quad (4)$$

$$\beta_s = E/12 \text{ for the supplemental GMD} \quad (5)$$

where, *E* is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event

The peak geoelectric field of the supplemental GMD event occurs in a localized area.[5] Planners have flexibility to determine how to apply the localized peak geoelectric field over the planning area in performing GIC calculations. Examples of approaches are:

- Apply the peak geoelectric field (12 V/km scaled to the planning area) over the entire planning area;
- Apply a spatially limited (12 V/km scaled to the planning area) peak geoelectric field (e.g., 100 km in North-South latitude direction and 500 km in East-West longitude direction) over a portion(s) of the system, and apply the benchmark GMD event over the rest of the system; or
- Other methods to adjust the benchmark GMD event analysis to account for the localized geoelectric field enhancement of the supplemental GMD event.

[4] Available at http://geomag.usgs.gov/conductivity/.

[5] See the Supplemental Geomagnetic Disturbance Description white paper located on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

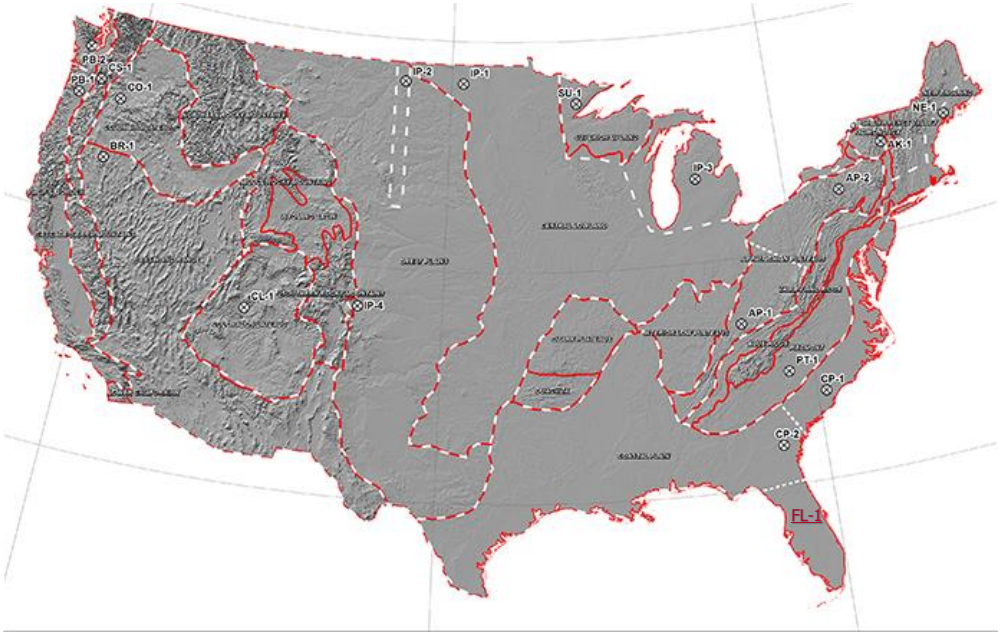


Figure 1: Physiographic Regions of the Continental United States[6]

Figure 2: Physiographic Regions of Canada

[6] Additional map detail is available at the U.S. Geological Survey: http://geomag.usgs.gov/.

Table 3: Geoelectric Field Scaling Factors		
Earth model	**Scaling Factor Benchmark Event (β_b)**	**Scaling Factor Supplemental Event (β_s)**
AK1A	0.56	0.51
AK1B	0.56	0.51
AP1	0.33	0.30
AP2	0.82	0.78
BR1	0.22	0.22
CL1	0.76	0.73
CO1	0.27	0.25
CP1	0.81	0.77
CP2	0.95	0.86
FL1	0.76	0.73
CS1	0.41	0.37
IP1	0.94	0.90
IP2	0.28	0.25
IP3	0.93	0.90
IP4	0.41	0.35
NE1	0.81	0.77
PB1	0.62	0.55
PB2	0.46	0.39
PT1	1.17	1.19
SL1	0.53	0.49
SU1	0.93	0.90
BOU	0.28	0.24
FBK	0.56	0.56
PRU	0.21	0.22
BC	0.67	0.62
PRAIRIES	0.96	0.88
SHIELD	1.0	1.0
ATLANTIC	0.79	0.76

Scaling factors in Table 3 are dependent upon the frequency content of the reference storm. Consequently, the benchmark GMD event and the supplemental GMD event may produce different scaling factors for a given earth model.

~~**Rationale:** Scaling factors in Table 3 are dependent upon the frequency content of the reference storm. Consequently, the benchmark GMD event and the supplemental GMD event may produce different scaling factors for a given earth model.~~

~~The scaling factor associated with the benchmark GMD event for the Florida earth model (FL1) has been updated based on the earth model published on the USGS public website.~~

Table 4: Reference Earth Model (Quebec)	
Layer Thickness (km)	**Resistivity (Ω-m)**
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveform for the Benchmark GMD Event[7]

The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). The sampling rate for the geomagnetic field waveform is 10 seconds.[8] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate benchmark conductivity scaling factor β_b.

[7] Refer to the Benchmark Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.

[8] The data file of the benchmark geomagnetic field waveform is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.

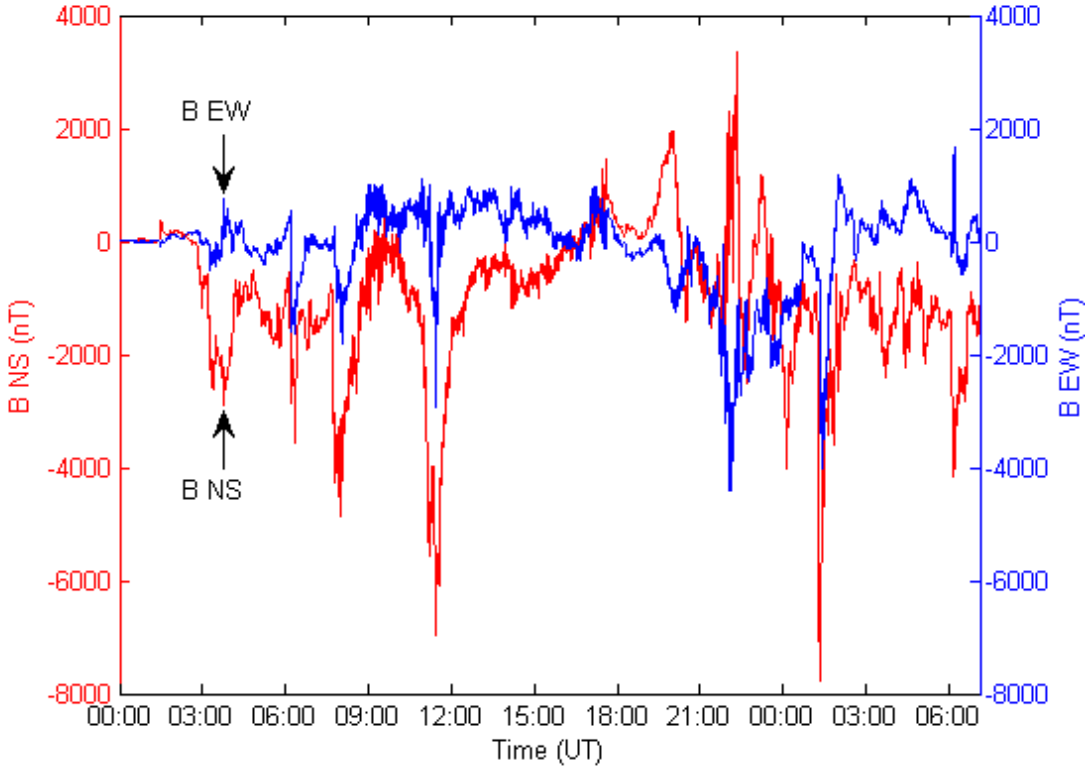


Figure 3: Benchmark Geomagnetic Field Waveform
Red B_n (Northward), Blue B_e (Eastward)

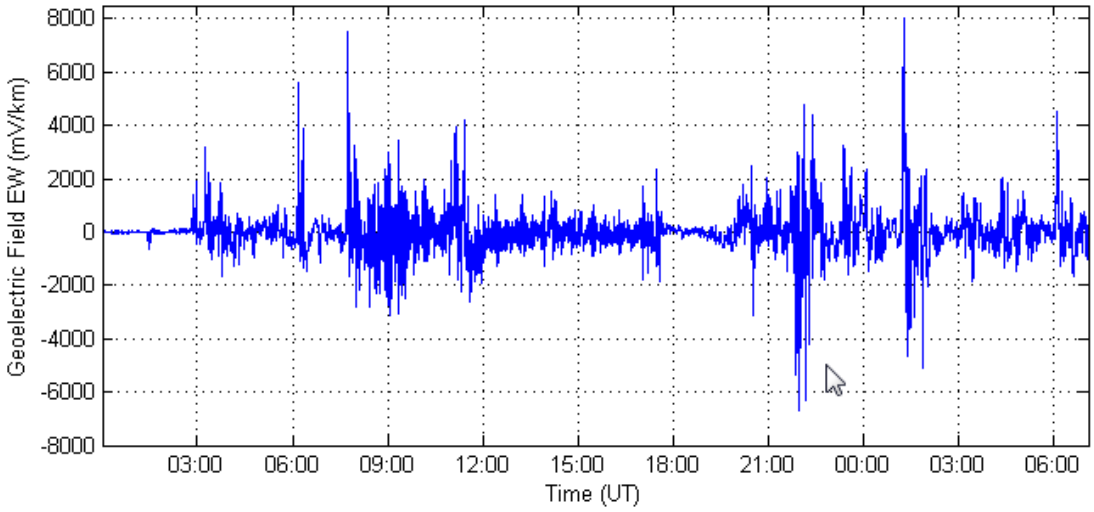


Figure 4: Benchmark Geoelectric Field Waveform
E_E (Eastward)

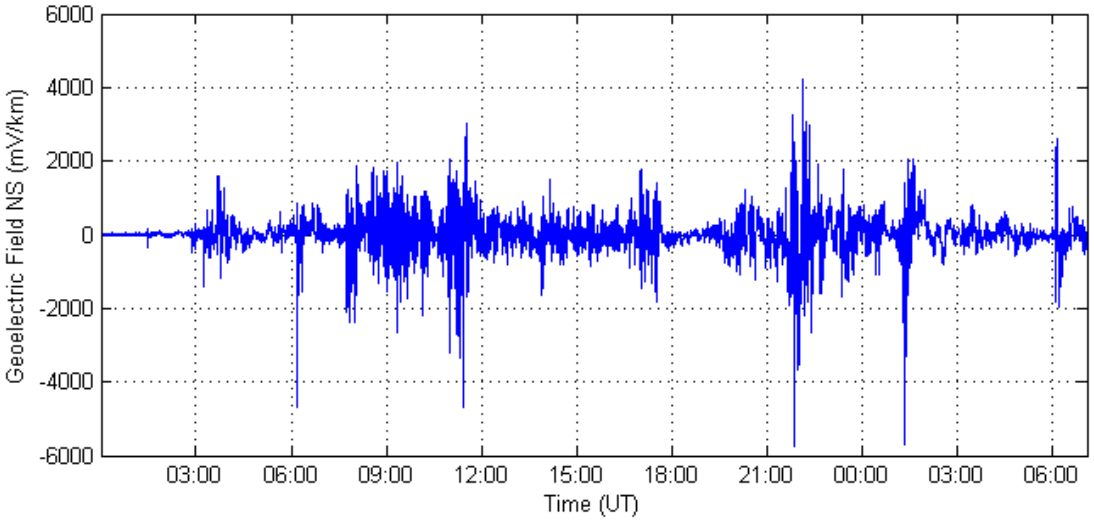


Figure 5: Benchmark Geoelectric Field Waveform
E_N (Northward)

Reference Geomagnetic Field Time Series or Waveform for the Supplemental GMD Event[9]

The geomagnetic field measurement record of the March 13-14, 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment for the supplemental GMD event. The supplemental GMD event waveform differs from the benchmark GMD event waveform in that the supplemental GMD event waveform has a local enhancement.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 6) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 12 V/km (see Figure7). The sampling rate for the geomagnetic field waveform is 10 seconds.[10] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate supplemental conductivity scaling factor β_s.

[9] Refer to the Supplemental Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

[10] The data file of the benchmark geomagnetic field waveform is available on the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

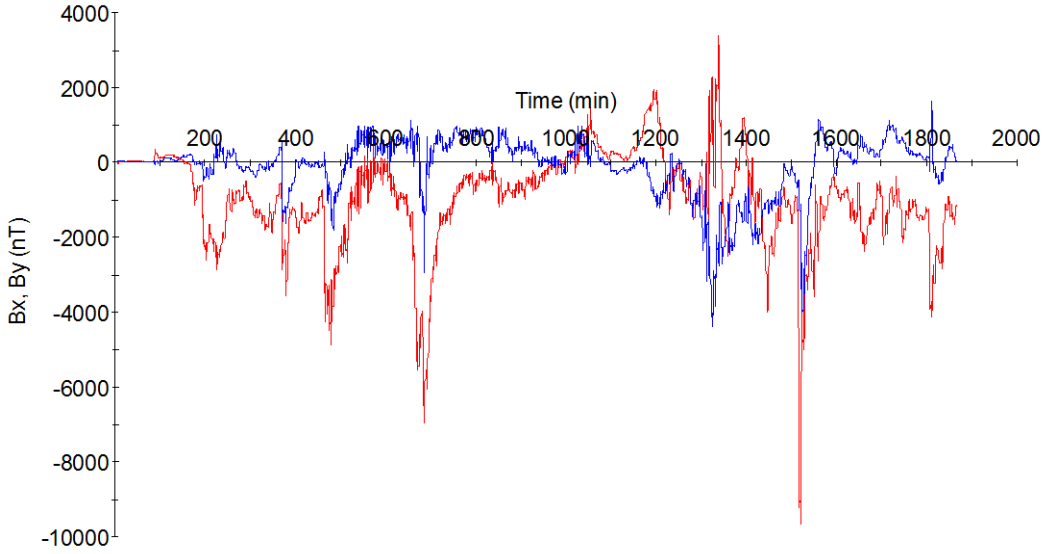


Figure 6: Supplemental Geomagnetic Field Waveform
Red B_N (Northward), Blue B_E (Eastward)

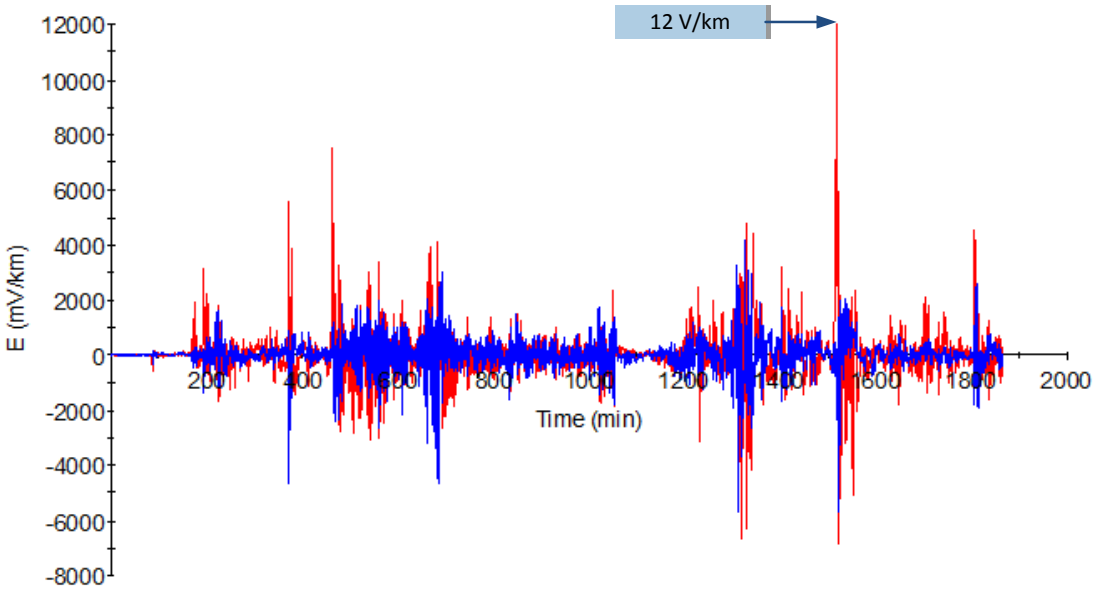


Figure 7: Supplemental Geoelectric Field Waveform
Blue E_N (Northward), Red E_E (Eastward)

Attachment 1-CAN

Attachment 1-CAN provides an alternative that a Canadian entity may use in lieu of the benchmark or supplemental GMD event(s) defined in Attachment 1 for performing GMD Vulnerability Assessment(s).

A Canadian entity may use the provisions of Attachment 1-CAN if it has regionally specific information that provides a technically justified means to re-define a 1-in-100 year GMD planning event(s) within its planning area.

Information for the Alternative Methodology

GMD Vulnerability Assessment(s) require the use of geophysical and engineering models. Canadian-specific data is available and growing. Ongoing research allows for more accurate characterization of regional parameters used in these models. Such Canadian-specific data includes geomagnetic field, earth conductivity, and geomagnetically induced current measurements that can be used for modeling and simulation validation.

Information used to calculate geoelectric fields for the benchmark and supplemental GMD events shall be clearly documented and technically justified. For example, the factors involved in the calculation of geoelectric fields are geomagnetic field variations and an earth transfer function(s).[1] ~~[1]~~ Technically justified information used in modelling geomagnetic field variations may include: technical documents produced by governmental entities such as Natural Resources Canada; technical papers published in peer-reviewed journals; and data sets gathered using sound scientific principles. An earth transfer function may rely on magnetotelluric measurements or earth conductivity models.

Modeling assumptions shall also be clearly documented and technically justified. An entity may use sensitivity analysis to identify how the assumptions affect the results.

A simplified model may be used to perform a GMD Vulnerability Assessment(s), as long as the model is more conservative than a more detailed model.

When interpreting assessment results, the entity shall consider the maturity of the modeling, toolset, and techniques applied.

Geomagnetic Disturbance Planning Events

The 1-in-100 year planning event shall be based on regionally specific data and technically justifiable statistical analyses (e.g., extreme value theory) and applied to the benchmark and supplemental GMD Vulnerability Assessment(s).

---

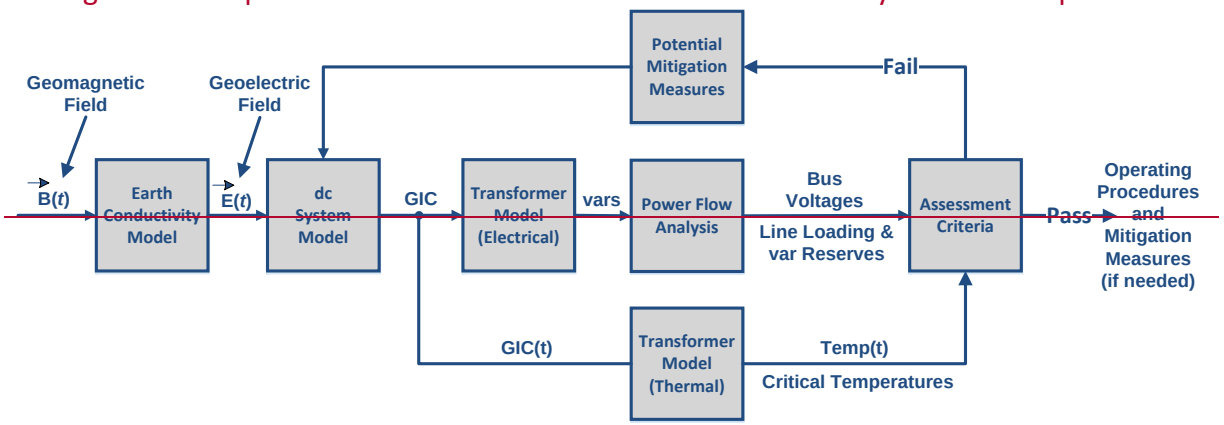
[1] The “earth transfer function” is the relationship between the electric fields and magnetic field variations at the surface of the earth.

~~[1] The “earth transfer function” is the relationship between the electric fields and magnetic field variations at the surface of the earth.~~

For the benchmark GMD Vulnerability Assessment(s), an entity shall consider the large-scale spatial structure of the GMD event. For the supplemental GMD Vulnerability Assessment(s), an entity shall consider the small-scale spatial structure of the GMD event (e.g., using magnetometer measurements or realistic electrojet calculations).

Guidelines and Technical Basis

The diagram below provides an overall view of the GMD Vulnerability Assessment process:



The requirements in this standard cover various aspects of the GMD Vulnerability Assessment process.

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. The *Benchmark Geomagnetic Disturbance Event Description*, May 2016[11] white paper includes the event description, analysis, and example calculations.

Supplemental GMD Event (Attachment 1)

The supplemental GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a supplemental GMD Vulnerability Assessment. The *Supplemental Geomagnetic Disturbance Event Description*, October 2017[12] white paper includes the event description and analysis.

Requirement R2

A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide:

[11] http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.
[12] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System, December 2013.[13]

Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations in the GIC system model, if applicable.

Requirement R4

The *Geomagnetic Disturbance Planning Guide*,[14] December 2013 developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies.

Requirement R5

The benchmark thermal impact assessment of transformers specified in Requirement R6 is based on GIC information for the benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for the benchmark thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.

GIC(t) provided in Part 5.2 is used to convert the steady state GIC flows to time series GIC data for the benchmark thermal impact assessment of transformers. This information may be needed by one or more of the methods for performing a benchmark thermal impact

[13] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf.
[14] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.

assessment. Additional information is in the following section and the *Transformer Thermal Impact Assessment White Paper,*[15] October 2017.

The peak GIC value of 75 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

Requirement R6

The benchmark thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment White Paper ERO Enterprise-Endorsed Implementation Guidance*[16] for this requirement. This ERO-Endorsed document is posted on the NERC Compliance Guidance[17] webpage.

Transformers are exempt from the benchmark thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper,*[18] October 2017. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.

The benchmark threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R7

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *Geomagnetic Disturbance Planning Guide,*[19] December 2013. Additional information is available in the *2012 Special Reliability Assessment*

[15] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.
[16] http://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-007-1_Transformer_Thermal_Impact_Assessment_White_Paper.pdf.
[17] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx.
[18] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.
[19] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.

Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System,[20] February 2012.

Requirement R8

The *Geomagnetic Disturbance Planning Guide,*[21] December 2013 developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies.

The supplemental GMD Vulnerability Assessment process is similar to the benchmark GMD Vulnerability Assessment process described under Requirement R4.

Requirement R9

The supplemental thermal impact assessment specified of transformers in Requirement R10 is based on GIC information for the supplemental GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R9 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 9.1 is used for the supplemental thermal impact assessment. Only those transformers that experience an effective GIC value of 85 A or greater per phase require evaluation in Requirement R10.

GIC(t) provided in Part 9.2 is used to convert the steady state GIC flows to time-series GIC data for the supplemental thermal impact assessment of transformers. This information may be needed by one or more of the methods for performing a supplemental thermal impact assessment. Additional information is in the following section.

The peak GIC value of 85 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

Requirement R10

The supplemental thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment White Paper ERO Enterprise-Endorsed Implementation Guidance*[22] discussed in the Requirement R6 section above. A later

[20] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf.
[21] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.
[22] http://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-007-1_Transformer_Thermal_Impact_Assessment_White_Paper.pdf.

version of the *Transformer Thermal Impact Assessment White Paper,*[23] October 2017, has been developed to include updated information pertinent to the supplemental GMD event and supplemental thermal impact assessment.

Transformers are exempt from the supplemental thermal impact assessment requirement if the effective GIC value for the transformer is less than 85 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the revised *Screening Criterion for Transformer Thermal Impact Assessment White Paper,*[24] October 2017. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R10.

The supplemental threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R11

Technical considerations for GIC monitoring are contained in Chapter 6 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System,*[25] February 2012. GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the wye-grounded transformer. Data from GIC monitors is useful for model validation and situational awareness.

Responsible entities consider the following in developing a process for obtaining GIC monitor data:

Monitor locations. An entity's operating process may be constrained by location of existing GIC monitors. However, when planning for additional GIC monitoring installations consider that data from monitors located in areas found to have high GIC based on system studies may provide more useful information for validation and situational awareness purposes. Conversely, data from GIC monitors that are located in the vicinity of transportation systems using direct current (e.g., subways or light rail) may be unreliable.

Monitor specifications. Capabilities of Hall effect transducers, existing and planned, should be considered in the operating process. When planning new GIC monitor installations, consider

[23] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.
[24] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.
[25] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf.

~~monitor data range (e.g., -500 A through + 500 A) and ambient temperature ratings consistent with temperatures in the region in which the monitor will be installed.~~

~~**Sampling Interval.** An entity's operating process may be constrained by capabilities of existing GIC monitors. However, when possible specify data sampling during periods of interest at a rate of 10 seconds or faster.~~

~~**Collection Periods.** The process should specify when the entity expects GIC data to be collected. For example, collection could be required during periods where the Kp index is above a threshold, or when GIC values are above a threshold. Determining when to discontinue collecting GIC data should also be specified to maintain consistency in data collection.~~

~~**Data format.** Specify time and value formats. For example, Greenwich Mean Time (GMT) (MM/DD/YYYY HH:MM:SS) and GIC Value (Ampere). Positive (+) and negative (-) signs indicate direction of GIC flow. Positive reference is flow from ground into transformer neutral. Time~~

~~fields should indicate the sampled time rather than system or SCADA time if supported by the GIC monitor system.~~

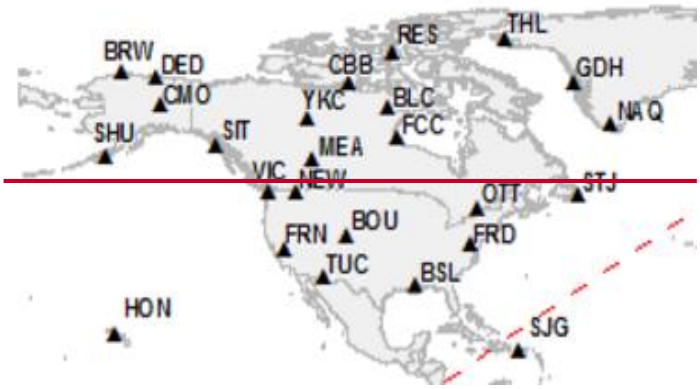
~~**Data retention.** The entity's process should specify data retention periods, for example 1 year. Data retention periods should be adequately long to support availability for the entity's model validation process and external reporting requirements, if any.~~

~~**Additional information.** The entity's process should specify collection of other information necessary for making the data useful, for example monitor location and type of neutral connection (e.g., three-phase or single-phase).~~

~~Requirement R12~~

~~Magnetometers measure changes in the earth's magnetic field. Entities should obtain data from the nearest accessible magnetometer. Sources of magnetometer data include:~~

~~Observatories such as those operated by U.S. Geological Survey and Natural Resources Canada, see figure below for locations:~~[26]



[26] ~~http://www.intermagnet.org/index-eng.php.~~

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

July 2019 - DRAFT Technical Rationale
Pending Submittal for ERO Enterprise Endorsement

Transmission System Planned Performance for Geomagnetic Disturbance Events

Technical Rationale and Justification for Reliability Standard TPL-007-4

July 2019

RELIABILITY | ACCOUNTABILITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

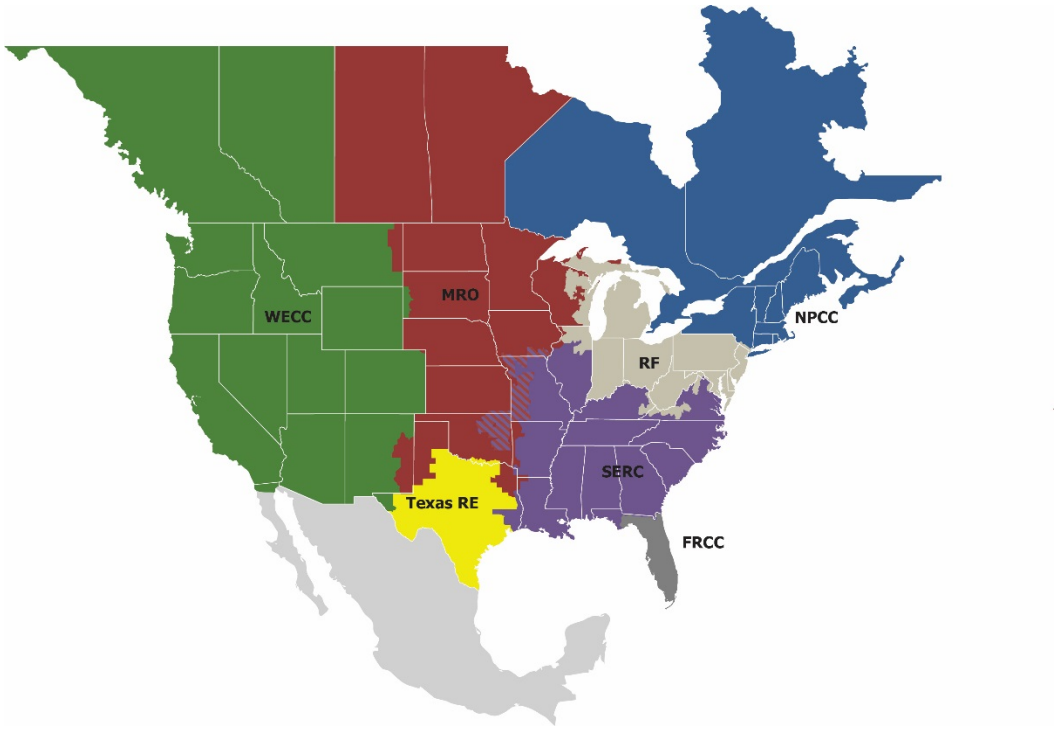
Table of Contents

Preface iii
Introduction iv
Background iv
Chapter 1 – General Considerations 1
Rationale for Applicability 1
Benchmark GMD Event (Attachment 1) 1
Supplemental GMD Event (Attachment 1) 1
Chapter 2 – Requirement R2 2
Chapter 3 – Requirement R4 3
Chapter 4 – Requirement R5 4
Chapter 5 – Requirement R6 5
Chapter 6 – Requirement R7 6
Chapter 7 – Supplemental GMD Vulnerability Assessment 7
Chapter 8 – Requirement R8 8
Chapter 9 – Requirement R9 9
Chapter 10 – Requirement R10 10
Chapter 11 – Requirement R11 11
Chapter 12 – Requirement R12 12
Chapter 13 – Requirement R13 13
References 14

Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into seven RE boundaries as shown in the map and corresponding table below. The multicolored area denotes 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
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

Background

This document explains the technical rationale and justification for the proposed Reliability Standard TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events. It provides stakeholders and the ERO Enterprise with an understanding of the technical requirements in the Reliability Standard. It also contains information on the standard drafting team's intent in drafting the requirements. This document, the Technical Rationale and Justification for TPL-007-4, is not a Reliability Standard and should not be considered mandatory and enforceable.

The first version of the standard, TPL-007-1, approved by FERC in Order No. 779 [1], requires entities to assess the impact to their systems from a defined event referred to as the "Benchmark GMD Event." The second version of the standard, TPL-007-2, adds new Requirements R8, R9, and R10 to require responsible entities to assess the potential implications of a "Supplemental GMD Event" on their equipment and systems in accordance with FERC's directives in Order No. 830 [2]. Some GMD events have shown localized enhancements of the geomagnetic field. The supplemental GMD event was developed to represent conditions associated with such localized enhancement during a severe GMD event for use in a GMD Vulnerability Assessment. The third version of the standard, TPL-007-3, adds a Canadian variance for Canadian Registered Entities to leverage operating experience, observed GMD effects, and on-going research efforts for defining alternative Benchmark GMD Events and/or Supplemental GMD Events that appropriately reflect Canadian-specific geographical and geological characteristics. No continent-wide requirements were changed between the second and the third versions of the standard. The fourth version of the standard, TPL-007-4, addresses the directives issued by FERC in Order No. 851 [3] to modify Reliability Standard TPL-007-3. FERC directed NERC to submit modifications to: (1) require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities (P 29); and (2) to replace the corrective action plan time-extension provision in TPL-007-3 with a process through which extensions of time are considered on a case-by-case basis (P 54).

The requirements in this standard cover various aspects of the GMD Vulnerability Assessment process. Figure 1 provides an overall view of the GMD Vulnerability Assessment process:

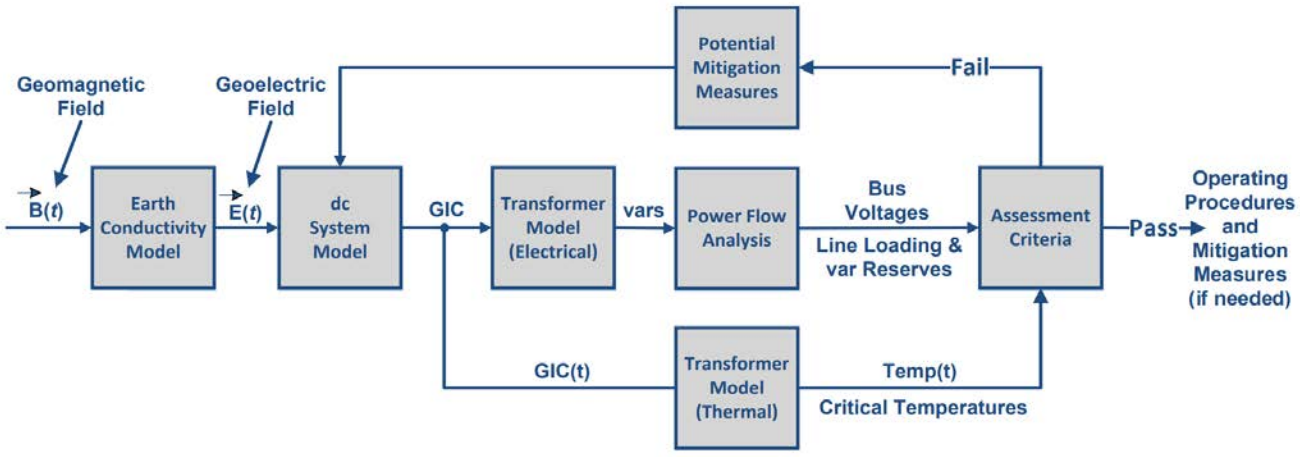


Figure 1. GMD Vulnerability Assessment Process.

Chapter 1 – General Considerations

Rationale for Applicability

Reliability Standard TPL-007-4 is applicable to Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these types of transformers are not included in the applicability for this standard. Terminal voltage describes line-to-line voltage.

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. The *Benchmark Geomagnetic Disturbance Event Description*, May 2016 [4], includes the event description, analysis, and example calculations.

Supplemental GMD Event (Attachment 1)

The supplemental GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a supplemental GMD Vulnerability Assessment. The *Supplemental Geomagnetic Disturbance Event Description*, October 2017 [5], includes the event description and analysis.

Chapter 2 – Requirement R2

A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the *Application Guide – Computing Geomagnetically-Induced Current in the Bulk-Power System*, December 2013 [6].

A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model is provided in the *Application Guide – Computing Geomagnetically-Induced Current in the Bulk-Power System*, December 2013 [6].

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformer(s) due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

Chapter 3 – Requirement R4

The *Geomagnetic Disturbance Planning Guide*, December 2013 [7], provides technical information on GMD-specific considerations for planning studies.

The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1: Steady State Planning GMD Event found in TPL-007-4. At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.

Chapter 4 – Requirement R5

The benchmark thermal impact assessment of transformers specified in Requirement R6 is based on GIC information for the benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information for the benchmark thermal impact assessment should be provided in accordance with Requirement R5 each time the benchmark GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The peak GIC value of 75 Amps per phase, in the benchmark GMD Vulnerability Assessment, has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

This GIC information is necessary for determining the benchmark thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the benchmark GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

GIC(t) provided in Part 5.2 can be used to convert the steady state GIC flows to time-series GIC data for the benchmark transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [8].

Chapter 5 – Requirement R6

The benchmark thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [9].

The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5.

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

Chapter 6 – Requirement R7

The requirement addresses directives in FERC Order No. 851 to replace the time-extension provision in Requirement R7.4 of TPL-007-2 (and TPL-007-3) with a process through which extensions of time are considered on a case-by-case basis.

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *Geomagnetic Disturbance Planning Guide*, December 2013 [7]. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [10].

Chapter 7 – Supplemental GMD Vulnerability Assessment

The requirements address directives in FERC Order No. 830 for revising the benchmark GMD event used in GMD Vulnerability Assessments (PP 44, 47-49). The requirements add a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for localized peak geoelectric fields.

Chapter 8 – Requirement R8

The *Geomagnetic Disturbance Planning Guide*, December 2013 [7], provides technical information on GMD-specific considerations for planning studies.

The supplemental GMD Vulnerability Assessment process is similar to the benchmark GMD Vulnerability Assessment process described under Requirement R4.

Chapter 9 – Requirement R9

The supplemental thermal impact assessment specified of transformers in Requirement R10 is based on GIC information for the supplemental GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information for the supplemental thermal impact assessment should be provided in accordance with Requirement R9 each time the supplemental GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The peak GIC value of 85 Amps per phase, in the supplemental GMD Vulnerability Assessment, has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

This GIC information is necessary for determining the supplemental thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the supplemental GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

GIC(t) provided in Part 9.2 can be used to convert the steady state GIC flows to time-series GIC data for the supplemental transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [8].

Chapter 10 – Requirement R10

The supplemental thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [9].

The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R9.

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

Chapter 11 – Requirement R11

The requirement addresses directives in FERC Order No. 851 to develop and submit modifications to Reliability Standard TPL-007-2 (and TPL-007-3) to require corrective action plans for the assessed supplemental GMD event vulnerabilities.

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the Geomagnetic Disturbance Planning Guide, December 2013 [7]. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [10].

Chapter 12 – Requirement R12

GMD measurement data refers to GIC monitor data and geomagnetic field data in Requirements R12 and R13, respectively. This requirement addresses directives in FERC Order No. 830 for requiring responsible entities to collect GIC monitoring data as necessary to enable model validation and situational awareness (PP 88, 90-92).

Technical considerations for GIC monitoring are contained in Chapter 9 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [10]. GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the wye-grounded transformer and measure dc current flowing through the neutral. Data from GIC monitors is useful for model validation and situational awareness.

The objective of Requirement R12 is for entities to obtain GIC data for the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model to inform GMD Vulnerability Assessments. Technical considerations for GIC monitoring are contained in Chapter 9 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [10].

Chapter 13 – Requirement R13

GMD measurement data refers to GIC monitor data and geomagnetic field data in Requirements R12 and R13, respectively. This requirement addresses directives in FERC Order No. 830 for requiring responsible entities to collect magnetometer data as necessary to enable model validation and situational awareness (PP 88, 90-92).

The objective of Requirement R13 is for entities to obtain geomagnetic field data for the Planning Coordinator's planning area to inform GMD Vulnerability Assessments.

Magnetometers provide geomagnetic field data by measuring changes in the earth's magnetic field. Sources of geomagnetic field data include:

- Observatories such as those operated by U.S. Geological Survey, Natural Resources Canada, research organizations, or university research facilities;
- Installed magnetometers; and
- Commercial or third-party sources of geomagnetic field data.

Geomagnetic field data for a Planning Coordinator’s planning area is obtained from one or more of the above data sources located in the Planning Coordinator’s planning area, or by obtaining a geomagnetic field data product for the Planning Coordinator’s planning area from a government or research organization. The geomagnetic field data product does not need to be derived from a magnetometer or observatory within the Planning Coordinator’s planning area.

References

1. FERC Order No. 779, https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Order779_GMD_RM12-22_20130516.pdf
2. FERC Order No. 830, https://www.nerc.com/filingsorders/us/FERCOrdersRules/E-4.pdf
3. FERC Order No. 851, https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/E-3_Order%20No%20851.pdf
4. Benchmark Geomagnetic Disturbance Event Description, NERC, Atlanta, GA, May 12, 2016, https://www.nerc.com/pa/Stand/TPL0071RD/Benchmark_clean_May12_complete.pdf
5. Supplemental Geomagnetic Disturbance Event Description, NERC, Atlanta, GA, October 2017, https://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/Supplemental_GMD_Event_Description_2017_October_Clean.pdf
6. Application Guide – Computing Geomagnetically-Induced Current in the Bulk-Power System, NERC, Atlanta, GA, December, 2013, https://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf
7. Geomagnetic Disturbance Planning Guide, NERC, Atlanta, GA, December, 2013, https://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf
8. Transformer Thermal Impact Assessment White Paper, NERC, Atlanta, GA, October 2017, https://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/Thermal_Impact_Assessment_2017_October_Clean.pdf
9. Screening Criterion for Transformer Thermal Impact Assessment White Paper, NERC, Atlanta, GA, October 2017, https://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/Screening_Criterion_Clean_2017_October_Clean.pdf
10. 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System, NERC, Atlanta, GA, February, 2012, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf

Consideration of Issues and Directives

Project 2019-01 Modifications to TPL-007-3

Project 2019-01 Modifications to TPL-007-3		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Modify the provision in Reliability Standard TPL-007-2, Requirement R7.4 that allows applicable entities to exceed deadlines for completing corrective action plan tasks when "situations beyond the control of the responsible entity [arise]", by requiring that NERC and the Regional Entities, as appropriate, consider requests for extension of time on a case-by-case basis. Under this option, responsible entities seeking an extension would submit the information required by Requirement R7.4 to NERC and the Regional Entities for their consideration of the request.	FERC Order No. 851, P 5 and P 50	The SDT proposed the modified language in Requirement R7.3 and R7.4 to require time extensions for completing CAPs be submitted to the ERO for approval. The proposed modified language reads as follows: 7.3. Include a timetable, subject ~~to revision by the responsible entity~~ ERO approval for any extension sought under ~~in~~ Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall: 7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and 7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP. 7.4. Be submitted to the ERO with a request for extension ~~revised~~ if ~~situations beyond the control of~~ the responsible entity is unable to ~~determined in Requirement R1 prevent~~ implement~~ation of~~ the CAP within the timetable ~~for implementation~~ provided in Part 7.3. The submitted ~~revised~~ CAP

Project 2019-01 Modifications to TPL-007-3		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		shall document the following~~, and be updated at least once every 12 calendar months until implemented~~: 7.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of each responsible entity; ~~7.4.2 Description of the original CAP, and any previous changes to the CAP, with the associated timetable(s) for implementing the selected actions in Part 7.1; and~~ 7.4.2 Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable~~;~~ and 7.4.3 ~~the u~~Updated timetable for implementing the selected actions in Part 7.1.
Submit modifications to Reliability Standard TPL-007-2 to require corrective action plans for assessed supplemental GMD event vulnerabilities.	FERC Order No. 851, P 4 and P 39	The SDT drafted TPL-007-4 Requirement R11 to address require CAPs for supplemental GMD vulnerabilities and to require extensions to these plans to be approved by NERC and the Regional Entities, as appropriate, in situations beyond the control of the responsible entity. This language is the same as the modified Requirement R7 which addresses CAPs for the benchmark GMD vulnerability assessment. Requirement R8 was also modified to remove the original R8.3 which stated "an evaluation of possible actions designed

Project 2019-01 Modifications to TPL-007-3		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted”

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

July 2019 - DRAFT Implementation Guidance
Pending Submittal for ERO Enterprise Endorsement

Transmission System Planned Performance for Geomagnetic Disturbance Events

Implementation Guidance for Reliability Standard TPL-007-4

July 2019

RELIABILITY | ACCOUNTABILITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

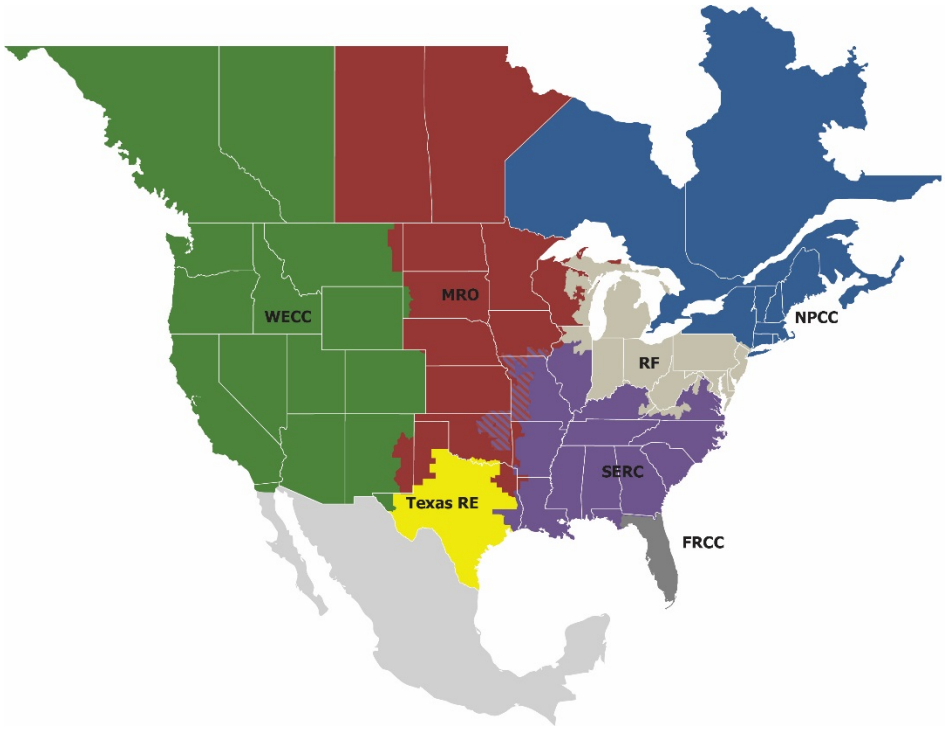
Table of Contents

Preface iii
Introduction iv
Background iv
Chapter 1 – Requirement R1 1
Chapter 2 – Requirement R2 2
Chapter 3 – Requirement R3 3
Chapter 4 – Requirement R4 4
Chapter 5 – Requirement R5 5
Chapter 6 – Requirement R6 6
Chapter 7 – Requirement R7 7
Chapter 8 – Supplemental GMD Vulnerability Assessment 8
Chapter 9 – Requirement R8 10
Chapter 10 – Requirement R9 11
Chapter 11 – Requirement R10 12
Chapter 12 – Requirement R11 13
Chapter 13 – Requirement R12 14
Chapter 14 – Requirement R13 15
References 16

Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into seven RE boundaries as shown in the map and corresponding table below. The multicolored area denotes 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
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

Background

The Standards Project 2019-01 Modifications to TPL-007-3 standard drafting team prepared this Implementation Guidance to provide example approaches for compliance with the modifications to TPL-007 - Transmission System Planned Performance for Geomagnetic Disturbance Events. Implementation Guidance does not prescribe the only approach, but highlights one or more approaches that would be effective in achieving compliance with the standard. Because Implementation Guidance only provides examples, entities may choose alternative approaches based on engineering judgement, individual equipment and system conditions.

The first version of the standard, TPL-007-1 which was approved in FERC's Order No. 779 [1], requires entities to assess the impact to their systems from a defined event referred to as the "Benchmark GMD Event." The second version of the standard, TPL-007-2, adds new Requirements R8, R9, and R10 to require responsible entities to assess the potential implications of a "Supplemental GMD Event" on their equipment and systems in accordance with FERC's directives in Order No. 830 [2]. Some GMD events have shown localized enhancements of the geomagnetic field. The supplemental GMD event was developed to represent conditions associated with such localized enhancement during a severe GMD event for use in a GMD Vulnerability Assessment. The third version of the standard, TPL-007-3, adds a Canadian variance for Canadian Registered Entities to leverage operating experience, observed GMD effects, and on-going research efforts for defining alternative Benchmark GMD Events and/or Supplemental GMD Events that appropriately reflect their specific geographical and geological characteristics. No continent-wide requirements were changed between the second and the third versions of the standard. The fourth version, TPL-007-4, addresses the directives issued by FERC in Order No. 851 [3] to modify Reliability Standard TPL-007-3. FERC directed NERC to submit modifications to: (1) require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities (P 29); and (2) to replace the corrective action plan time-extension provision in TPL-007-3 Requirement R7.4 with a process through which extensions of time are considered on a case-by-case basis (P 54).

Chapter 1 – Requirement R1

In some areas, planning entities may determine that the most effective approach to conduct a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

Chapter 2 – Requirement R2

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These system adjustments could for example include recalling or postponing maintenance outages.

Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations, such as this, in the GIC system model, if applicable.

Chapter 3 – Requirement R3

Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1: Steady State Planning GMD Event found in TPL-007-4. Steady state voltage limits are an example of System steady state performance criteria.

Chapter 4 – Requirement R4

Distribution of benchmark GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be considered by transmission planners.

The provision of information in Requirement R4, Part 4.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 5 – Requirement R5

The maximum effective GIC value provided in Part 5.1 is used for the benchmark thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1.

The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 6 – Requirement R6

ERO Enterprise-Endorsed Implementation Guidance for conducting the thermal impact assessment of a power transformer is presented in the *Transformer Thermal Impact Assessment White Paper*, October 2016 [4].

Transformers are exempt from the benchmark thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.

The benchmark threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the above referenced white paper and *the Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [5], for additional information.

Approaches for conducting the thermal impact assessment of transformers for the benchmark event are presented in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [6].

Thermal impact assessments for the benchmark event are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4) and the Corrective Action Plan (CAP; R7) as necessary.

The provision of information in Requirement R6, Part 6.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 7 – Requirement R7

The proposed requirement addresses directives in FERC Order No. 830 for establishing CAP deadlines associated with GMD Vulnerability Assessments. In FERC Order No. 830, FERC directed revisions to TPL-007 such that CAPs are developed within one year from the completion of GMD Vulnerability Assessments (P 101). Furthermore, FERC directed NERC to establish implementation deadlines after the completion of the CAP as follows (P 102):

- Two years for non-hardware mitigation; and
- Four years for hardware mitigation.

Part 7.4 requires entities to submit to the ERO with a request for extension when implementation of planned mitigation is not achievable within the deadlines established in Part 7.3. Examples of situations beyond the control of the responsible entity include, but are not limited to:

- Delays resulting from regulatory/legal processes, such as permitting;
- Delays resulting from stakeholder processes required by tariff;
- Delays resulting from equipment lead times; or
- Delays resulting from the inability to acquire necessary Right-of-Way.

Chapter 8 – Supplemental GMD Vulnerability Assessment

The exact spatial extent, local time of occurrence, latitude boundary, number of occurrences during a GMD event, and geoelectric field characteristics (amplitude and orientation) inside/outside the local enhancement cannot yet be scientifically determined.

TPL-007-4 provides flexibility for Transmission Planners to determine how to apply the supplemental GMD event to the planning area. This guide provides acceptable approaches and boundaries to apply the supplemental event.

1. Spatial extent:
    a. The local geoelectric field enhancement should not be smaller than 100 km (West-East) by 100 km (North-South).
    b. The transmission planner may perform a sensitivity analysis varying the spatial extent. Note that the 100 km North-South spatial extent is better understood than the West-East length, which could be 500 km or more.
    c. The peak geoelectric field for the supplemental GMD event (12 V/km scaled to the planning area) can be applied over the entire planning area. Note that this implies studying a GMD event rarer than 1-in-100 years.
2. Geoelectric field inside the local enhancement:
    a. Amplitude: 12 V/km (scaled to the planning area).
    b. Orientation: at a minimum, a West-East[1] orientation should be considered when applying the supplemental event.
    c. The transmission planner may perform a sensitivity analysis varying the orientation of the geoelectric field.
3. Geoelectric field outside[2] the local enhancement:
    a. Amplitude: should not be smaller than 1.2 V/km (scaled to the planning area); i.e., an order of magnitude smaller than the field inside the local enhancement.
    b. Orientation: at a minimum, a West-East[3] orientation should be considered when applying the supplemental event.
    c. The transmission planner may perform a sensitivity analysis varying the orientation of the geoelectric field.
4. Position of the local enhancement:
    a. The transmission planner may use engineering judgement to position the local enhancement on critical areas of their system. For example, the benchmark vulnerability assessment may identify areas with depressed voltages, lack of dynamic reactive reserves, large GIC flows through transformers, etc. The transmission planner may also consider the impact to critical infrastructure or other externalities.
    b. The transmission planner may systematically move the position of the local enhancement throughout the entire planning area.

[1] West-East geomagnetic reference.

[2] The characteristics of the geoelectric field outside the local enhancement, for example amplitude, orientation, spatial extent, are still being reviewed by the scientific community.

[3] West-East geomagnetic reference.

c. Despite the fact that local enhancements appear to be limited to auroral regions, geomagnetic latitude should not be used as a criterion to position the local enhancement.

The schematic in Figure 1 illustrates the boundaries to apply the supplemental GMD event. The local enhancement should not be smaller than 100 km by 100 km, the geoelectric field inside the local enhancement is 12 V/km (scaled to the planning area) with West-East orientation, and the geoelectric field outside the local enhancement could be as low as 1.2 V/km (scaled to the planning area) with a West-East orientation.

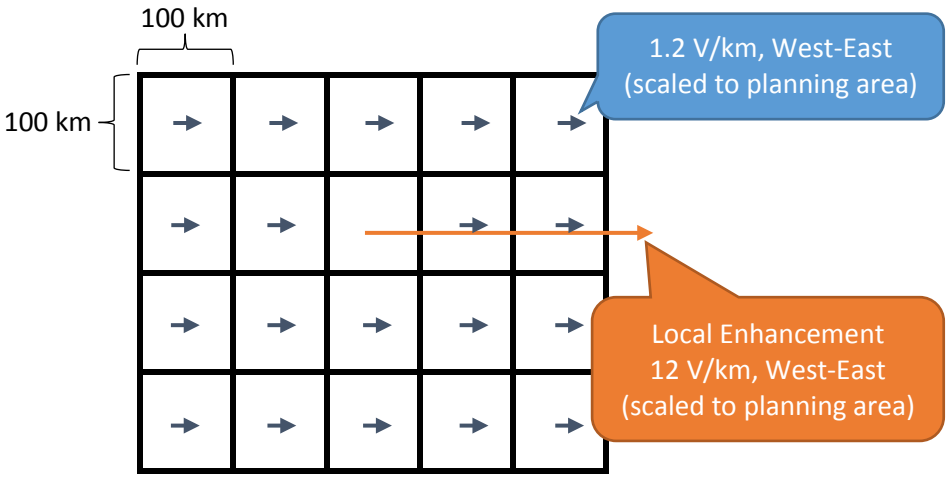


Figure 1. Schematic showing the boundaries to apply the supplemental event.

Chapter 9 – Requirement R8

Distribution of supplemental GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be considered by transmission planners.

The provision of information in Requirement R8, Part 8.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 10 – Requirement R9

The maximum effective GIC value provided in Part 9.1 is used for the supplemental thermal impact assessment. Only those transformers that experience an effective GIC value of 85 A or greater per phase require evaluation in Requirement R10.

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R9, Part 9.1.

The provision of information in Requirement R9 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 11 – Requirement R10

ERO Enterprise-Endorsed Implementation Guidance for conducting the thermal impact assessment of a power transformer is presented in the *Transformer Thermal Impact Assessment White Paper*, October 2016 [4].

Transformers are exempt from the supplemental thermal impact assessment requirement if the effective GIC value for the transformer is less than 85 A per phase, as determined by a GIC analysis of the System. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R10.

The supplemental threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the above referenced white paper and the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [5] for additional information.

Approaches for conducting the thermal impact assessment of transformers for the supplemental event are presented in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [6].

Thermal impact assessments for the supplemental event are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R8) and the Corrective Action Plan (R11) as necessary.

The provision of information in Requirement R10, Part 10.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 12 – Requirement R11

The requirement addresses directives in FERC Order No. 851 to develop and submit modifications to Reliability Standard TPL-007-2 (and TPL-007-3) to require corrective action plans for assessed supplemental GMD event vulnerabilities. This requirement is analogous to Requirement R7, such that CAPs are developed within one year from the completion of supplemental GMD Vulnerability Assessments and establishment of implementation deadlines after the completion of the CAP as follows:

- Two years for non-hardware mitigation; and
- Four years for hardware mitigation.

Part 11.4 requires entities to submit to the ERO with a request for extension when implementation of planned mitigation is not achievable within the deadlines established in Part 11.3. Examples of situations beyond the control of the responsible entity include, but are not limited to:

- Delays resulting from regulatory/legal processes, such as permitting;
- Delays resulting from stakeholder processes required by tariff;
- Delays resulting from equipment lead times; or
- Delays resulting from the inability to acquire necessary Right-of-Way.

Chapter 13 – Requirement R12

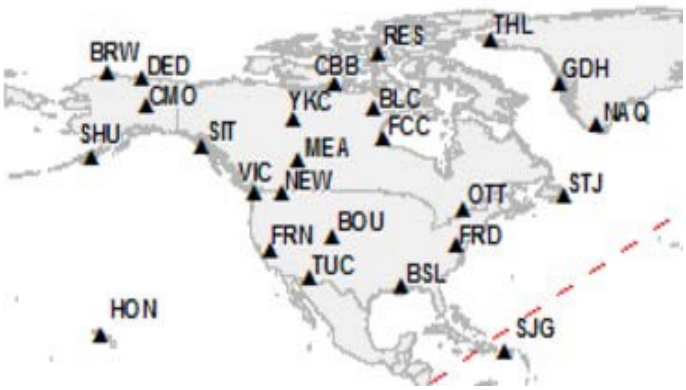
Responsible entities consider the following in developing a process for obtaining GIC monitor data:

- Monitor locations. An entity's operating process may be constrained by location of existing GIC monitors. However, when planning for additional GIC monitoring installations consider that data from monitors located in areas found to have high GIC based on system studies may provide more useful information for validation and situational awareness purposes. Conversely, data from GIC monitors that are located in the vicinity of transportation systems using direct current (for example subways or light rail) may be unreliable.
- Monitor specifications. Capabilities of Hall effect transducers, existing and planned, should be considered in the operating process. When planning new GIC monitor installations, consider monitor data range (for example -500 A through + 500 A) and ambient temperature ratings consistent with temperatures in the region in which the monitor will be installed.
- Sampling Interval. An entity's operating process may be constrained by capabilities of existing GIC monitors. However, when possible specify data sampling during periods of interest at a rate of 10 seconds or faster.
- Collection Periods. The process should specify when the entity expects GIC data to be collected. For example, collection could be required during periods where the Kp index is above a threshold, or when GIC values are above a threshold. Determining when to discontinue collecting GIC data should also be specified to maintain consistency in data collection.
- Data format. Specify time and value formats. For example, Greenwich Mean Time (GMT) (MM/DD/YYYY HH:MM:SS) and GIC Value (Ampere). Positive (+) and negative (-) signs indicate direction of GIC flow. Positive reference is flow from ground into transformer neutral. Time fields should indicate the sampled time rather than system or SCADA time if supported by the GIC monitor system.
- Data retention. The entity's process should specify data retention periods, for example one (1) year. Data retention periods should be adequately long to support availability for the entity's model validation process and external reporting requirements, if any.
- Additional information. The entity's process should specify collection of other information necessary for making the data useful, for example monitor location and type of neutral connection (for example three-phase or single-phase).

Chapter 14 – Requirement R13

Magnetometers measure changes in the earth's magnetic field. Entities should obtain data from the nearest accessible magnetometer. Sources of magnetometer data include:

- Observatories such as those operated by U.S. Geological Survey (USGS) and Natural Resources Canada (NRCan), see figure below for locations [7];



- Research institutions and academic universities; and
- Entities with installed magnetometers.

Entities that choose to install magnetometers should consider equipment specifications and data format protocols contained in the *INTERMAGNET Technical Reference Manual*, Version 4.6, 2012 [8].

References

1. FERC Order No. 779, https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Order779_GMD_RM12-22_20130516.pdf
2. FERC Order No. 830, https://www.nerc.com/filingsorders/us/FERCOrdersRules/E-4.pdf
3. FERC Order No. 851, https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/E-3_Order%20No%20851.pdf
4. Transformer Thermal Impact Assessment White Paper, ERO Enterprise-Endorsed Implementation Guidance, NERC, Atlanta, GA, October 28, 2016, https://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-007-1_Transformer_Thermal_Impact_Assessment_White_Paper.pdf
5. Screening Criterion for Transformer Thermal Impact Assessment White Paper, NERC, Atlanta, GA, October 2017, https://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/Screening_Criterion_Clean_2017_October_Clean.pdf
6. Transformer Thermal Impact Assessment White Paper, NERC, Atlanta, GA, October 2017, https://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/Thermal_Impact_Assessment_2017_October_Clean.pdf
7. International Real-Time Magnetic Observatory Network, http://www.intermagnet.org/index-eng.php
8. INTERMAGNET Technical Reference Manual, Version 4.6, 2012, http://www.intermagnet.org/publications/intermag_4-6.pdf

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DRAFT TPL-007-4 CAP Extension Request Review Process

DRAFT

RELIABILITY | RESILIENCE | SECURITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Table of Contents

Introduction iii
Background iii
Process Overview 1
Step 1 – Registered Entity Submittal 1
Step 2 – ERO Enterprise Review 1
Step 3 – Registered Entity Notification 1
Appendix A : Entity Submittal Template 2

DRAFT

Introduction

Background

This Electric Reliability Organization (ERO) Enterprise[1] TPL-007-4 Corrective Action Plan (CAP) Extension Review Process document addresses how ERO Enterprise Compliance Monitoring and Enforcement staff (CMEP staff) will jointly review requests for extensions to Corrective Action Plans (CAPs) developed under TPL-007-4 to ensure a timely, structured and consistent approach to CAP extension request submittals and processing.

NERC Compliance Assurance will maintain this document under existing ERO Enterprise processes. This document will be reviewed and updated by NERC Compliance Assurance, as needed.

DRAFT

[1] The ERO Enterprise is comprised of NERC and the Regional Entities.

Process Overview

If a registered entity (entity) has determined that a Corrective Action Plan (CAP) developed in accordance with TPL-007-4 R7 or R11 cannot be met in the timetable provided per Part 7.3 or 11.3 due to situations beyond the control of the responsible entity, then the entity will submit a extension request to the ERO Enterprise for approval prior to the original required CAP completion date.

The steps outlined here should be followed to ensure a timely, structured and consistent approach to extension request submittals and processing.

Step 1 – Registered Entity Submittal

If a registered entity (entity) determines that it cannot meet the required timetable for completing a CAP, the entity will contact their Compliance Enforcement Authority (CEA) to coordinate submittal of an extension request. The entity should submit the request to their CEA using the template provided in **Appendix A: Entity Submittal Template** or through an alternate method designated by the CEA that includes the same information.

Entities are encouraged to submit the extension request as soon as they are aware they will not meet the CAP completion date to allow the ERO Enterprise time to approve the extension request before the original required completion date.

All CAP extension requests must be approved by the ERO Enterprise prior to original required CAP completion date.

Step 2 – ERO Enterprise Review

The CEA will ensure that all information detailed in TPL-007-4 Part 7.4 or 11.4 and requested in the Entity Submittal Template is provided in the entity's extension request submittal. The CEA will work with the entity to provide any missing information.

The CEA will notify NERC of the extension request submittal. The CEA and NERC will then perform a joint review of (1) the situation(s) beyond the control of the entity preventing implementation of the CAP within the identified timetable; and (2) the revisions to the CAP and updated timetable for implementing the selected actions. Any additional information requested by the ERO Enterprise to support the extension request review will be coordinated by the CEA.

The Standard language states that an entity will submit an extension request for a full or partial delay in the implementation of the CAP within the timetable provided in TPL-007-4 Part 7.3 or 11.3. The CEA and NERC will determine whether to approve the extension request based on the specific facts and circumstances provided as to how the situations causing the delay in completing the CAP are beyond the control of the entity.

Step 3 – Registered Entity Notification

The CEA will communicate the ERO Enterprise approval or denial of the extension request to the entity along with the rationale for the determination.

DRAFT

Appendix A: Entity Submittal Template

[Will be formatted into a form for submission that includes the following information]

Entity name:

NCR#:

Primary entity contact name and information:

Coordinated Oversight Group # (if applicable):

Regional Entities impacted (for MRREs only):

Start date of CAP:

Original completion date of CAP:

Description of system deficiencies identified and selected actions to achieve required System performance per TPL-007-4 Part 7.1:

Circumstances causing the delay for fully or partially implementing the selected actions:

Description of revisions to the selected actions, if applicable:

New proposed completion date of CAP:

DRAFT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2019-01 Modifications to TPL-007-3

Applicable Standard

- TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Requested Retirement

- TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Standard

None

Applicable Entities

- *Planning Coordinator with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;*
- *Transmission Planner with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;*
- *Transmission Owner who owns a Facility or Facilities specified in Section 4.2 of the standard; and*
- *Generator Owner who owns a Facility or Facilities specified in Section 4.2 of the standard*.

Section 4.2 states that the standard applies to facilities that include power transformer(s) with a high-side, wye-grounded winding with terminal voltage greater than 200 kV.

Terms in the NERC Glossary of Terms

There are no new, modified, or retired terms.

Background

On November 15, 2018, the Federal Energy Regulatory Commission (FERC) issued Order No. 851 approving Reliability Standard TPL-007-2 and its associated implementation plan. In the order, FERC also directed NERC to develop certain modifications to the standard. FERC established a deadline of 12 months from the effective date of Reliability Standard TPL-007-2 to submit a revised standard (July 1, 2020).

On February 7, 2019, the NERC Board of Trustees adopted Reliability Standard TPL-007-3, which added a Variance option for applicable entities in Canadian jurisdictions. No continent-wide requirements were changed. Under the terms of its implementation plan, Reliability Standard TPL-007-3 became effective in the United States on July 1, 2019. All phased-in compliance dates from the TPL-007-2 implementation plan were carried forward unchanged in the TPL-007-3 implementation plan.

General Considerations

This implementation plan is intended to integrate the new and revised requirements in TPL-007-4 in the existing timeframe under the TPL-007-3 implementation plan.

Effective Date

The effective date for the proposed Reliability Standard is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of the proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. These phased-in compliance dates represent the dates that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Reliability Standard TPL-007-4

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 six (6) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Phased-In Compliance Dates

Compliance Date for TPL-007-4 Requirements R1, R2, R5, and R9

Entities shall be required to comply with Requirements R1, R2, R5, and R9 upon the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R12 and R13

Entities shall not be required to comply with Requirements R12 and R13 until the later of: (i) July 1, 2021; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R6 and R10

Entities shall not be required to comply with Requirements R6 and R10 until the later of: (i) January 1, 2022; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R3, R4, and R8

Entities shall not be required to comply with Requirements R3, R4, and R8 until the later of: (i) January 1, 2023; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirement R7
Entities shall not be required to comply with Requirement R7 until the later of: (i) January 1, 2024; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirement R11
Entities shall not be required to comply with Requirement R11 until the later of: (i) January 1, 2024; or (ii) six (6) months after the effective date of Reliability Standard TPL-007-4.

Retirement Date

Standard TPL-007-3
Reliability Standard TPL-007-3 shall be retired immediately prior to the effective date of TPL-007-4 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance of Periodic Requirements

Transmission Owners and Generator Owners are not required to comply with Requirement R6 prior to the compliance date for Requirement R6, regardless of when geomagnetically-induced current (GIC) flow information specified in Requirement R5, Part 5.1 is received.

Transmission Owners and Generator Owners are not required to comply with Requirement R10 prior to the compliance date for Requirement R10, regardless of when GIC flow information specified in Requirement R9, Part 9.1 is received.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

July 2019 - DRAFT Implementation Guidance
Pending Submittal for ERO Enterprise Endorsement

Transmission System Planned Performance for Geomagnetic Disturbance Events

Implementation Guidance for Reliability Standard TPL-007-4

July 2019

RELIABILITY | ACCOUNTABILITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

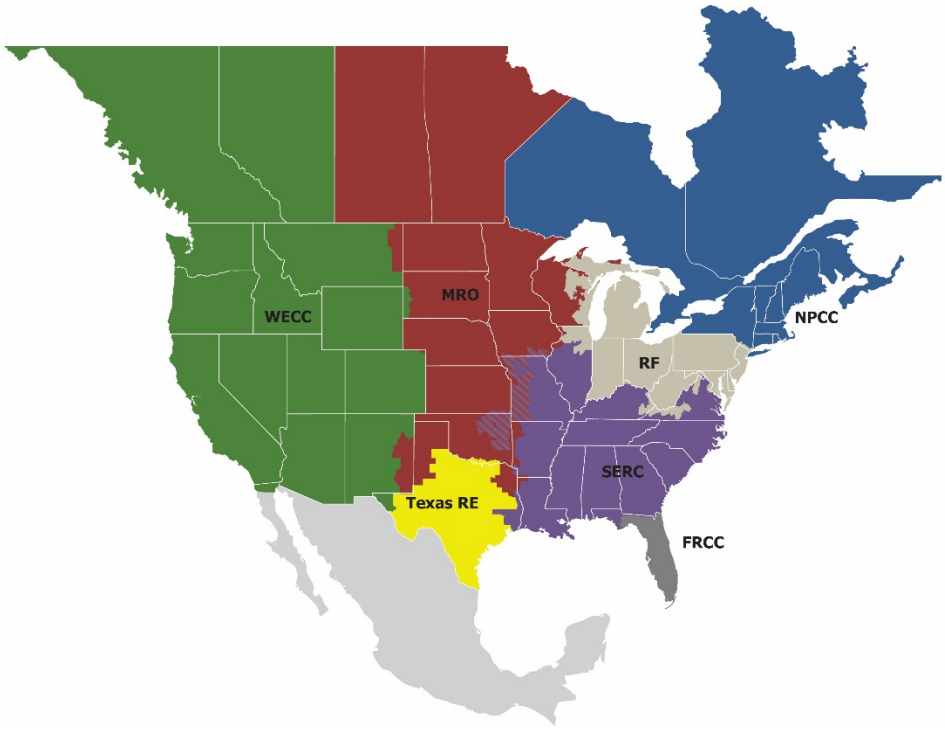
Table of Contents

Preface iii
Introduction iv
Background iv
Chapter 1 – Requirement R1 1
Chapter 2 – Requirement R2 2
Chapter 3 – Requirement R3 3
Chapter 4 – Requirement R4 4
Chapter 5 – Requirement R5 5
Chapter 6 – Requirement R6 6
Chapter 7 – Requirement R7 7
Chapter 8 – Supplemental GMD Vulnerability Assessment 8
Chapter 9 – Requirement R8 10
Chapter 10 – Requirement R9 11
Chapter 11 – Requirement R10 12
Chapter 12 – Requirement R11 13
Chapter 13 – Requirement R12 14
Chapter 14 – Requirement R13 15
References 16

Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into seven RE boundaries as shown in the map and corresponding table below. The multicolored area denotes 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
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

Background

The Standards Project 2019-01 Modifications to TPL-007-3 standard drafting team prepared this Implementation Guidance to provide example approaches for compliance with the modifications to TPL-007 - Transmission System Planned Performance for Geomagnetic Disturbance Events. Implementation Guidance does not prescribe the only approach, but highlights one or more approaches that would be effective in achieving compliance with the standard. Because Implementation Guidance only provides examples, entities may choose alternative approaches based on engineering judgement, individual equipment and system conditions.

The first version of the standard, TPL-007-1 which was approved in FERC's Order No. 779 [1], requires entities to assess the impact to their systems from a defined event referred to as the "Benchmark GMD Event." The second version of the standard, TPL-007-2, adds new Requirements R8, R9, and R10 to require responsible entities to assess the potential implications of a "Supplemental GMD Event" on their equipment and systems in accordance with FERC's directives in Order No. 830 [2]. Some GMD events have shown localized enhancements of the geomagnetic field. The supplemental GMD event was developed to represent conditions associated with such localized enhancement during a severe GMD event for use in a GMD Vulnerability Assessment. The third version of the standard, TPL-007-3, adds a Canadian variance for Canadian Registered Entities to leverage operating experience, observed GMD effects, and on-going research efforts for defining alternative Benchmark GMD Events and/or Supplemental GMD Events that appropriately reflect their specific geographical and geological characteristics. No continent-wide requirements were changed between the second and the third versions of the standard. The fourth version, TPL-007-4, addresses the directives issued by FERC in Order No. 851 [3] to modify Reliability Standard TPL-007-3. FERC directed NERC to submit modifications to: (1) require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities (P 29); and (2) to replace the corrective action plan time-extension provision in TPL-007-3 Requirement R7.4 with a process through which extensions of time are considered on a case-by-case basis (P 54).

Chapter 1 – Requirement R1

In some areas, planning entities may determine that the most effective approach to conduct a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

Chapter 2 – Requirement R2

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These system adjustments could for example include recalling or postponing maintenance outages.

Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations, such as this, in the GIC system model, if applicable.

Chapter 3 – Requirement R3

Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1: Steady State Planning GMD Event found in TPL-007-4. Steady state voltage limits are an example of System steady state performance criteria.

Chapter 4 – Requirement R4

Distribution of benchmark GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be considered by transmission planners.

The provision of information in Requirement R4, Part 4.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 5 – Requirement R5

The maximum effective GIC value provided in Part 5.1 is used for the benchmark thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1.

The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 6 – Requirement R6

ERO Enterprise-Endorsed Implementation Guidance for conducting the thermal impact assessment of a power transformer is presented in the *Transformer Thermal Impact Assessment White Paper*, October 2016 [4].

Transformers are exempt from the benchmark thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.

The benchmark threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the above referenced white paper and *the Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [5], for additional information.

Approaches for conducting the thermal impact assessment of transformers for the benchmark event are presented in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [6].

Thermal impact assessments for the benchmark event are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4) and the Corrective Action Plan (CAP; R7) as necessary.

The provision of information in Requirement R6, Part 6.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 7 – Requirement R7

The proposed requirement addresses directives in FERC Order No. 830 for establishing CAP deadlines associated with GMD Vulnerability Assessments. In FERC Order No. 830, FERC directed revisions to TPL-007 such that CAPs are developed within one year from the completion of GMD Vulnerability Assessments (P 101). Furthermore, FERC directed NERC to establish implementation deadlines after the completion of the CAP as follows (P 102):

- Two years for non-hardware mitigation; and
- Four years for hardware mitigation.

Part 7.4 requires entities to submit to the ERO with a request for extension when implementation of planned mitigation is not achievable within the deadlines established in Part 7.3. Examples of situations beyond the control of the responsible entity include, but are not limited to:

- Delays resulting from regulatory/legal processes, such as permitting;
- Delays resulting from stakeholder processes required by tariff;
- Delays resulting from equipment lead times; or
- Delays resulting from the inability to acquire necessary Right-of-Way.

Chapter 8 – Supplemental GMD Vulnerability Assessment

The exact spatial extent, local time of occurrence, latitude boundary, number of occurrences during a GMD event, and geoelectric field characteristics (amplitude and orientation) inside/outside the local enhancement cannot yet be scientifically determined.

TPL-007-4 provides flexibility for Transmission Planners to determine how to apply the supplemental GMD event to the planning area. This guide provides acceptable approaches and boundaries to apply the supplemental event.

1. Spatial extent:
    a. The local geoelectric field enhancement should not be smaller than 100 km (West-East) by 100 km (North-South).
    b. The transmission planner may perform a sensitivity analysis varying the spatial extent. Note that the 100 km North-South spatial extent is better understood than the West-East length, which could be 500 km or more.
    c. The peak geoelectric field for the supplemental GMD event (12 V/km scaled to the planning area) can be applied over the entire planning area. Note that this implies studying a GMD event rarer than 1-in-100 years.
2. Geoelectric field inside the local enhancement:
    a. Amplitude: 12 V/km (scaled to the planning area).
    b. Orientation: at a minimum, a West-East[1] orientation should be considered when applying the supplemental event.
    c. The transmission planner may perform a sensitivity analysis varying the orientation of the geoelectric field.
3. Geoelectric field outside[2] the local enhancement:
    a. Amplitude: should not be smaller than 1.2 V/km (scaled to the planning area); i.e., an order of magnitude smaller than the field inside the local enhancement.
    b. Orientation: at a minimum, a West-East[3] orientation should be considered when applying the supplemental event.
    c. The transmission planner may perform a sensitivity analysis varying the orientation of the geoelectric field.
4. Position of the local enhancement:
    a. The transmission planner may use engineering judgement to position the local enhancement on critical areas of their system. For example, the benchmark vulnerability assessment may identify areas with depressed voltages, lack of dynamic reactive reserves, large GIC flows through transformers, etc. The transmission planner may also consider the impact to critical infrastructure or other externalities.
    b. The transmission planner may systematically move the position of the local enhancement throughout the entire planning area.

[1] West-East geomagnetic reference.

[2] The characteristics of the geoelectric field outside the local enhancement, for example amplitude, orientation, spatial extent, are still being reviewed by the scientific community.

[3] West-East geomagnetic reference.

c. Despite the fact that local enhancements appear to be limited to auroral regions, geomagnetic latitude should not be used as a criterion to position the local enhancement.

The schematic in Figure 1 illustrates the boundaries to apply the supplemental GMD event. The local enhancement should not be smaller than 100 km by 100 km, the geoelectric field inside the local enhancement is 12 V/km (scaled to the planning area) with West-East orientation, and the geoelectric field outside the local enhancement could be as low as 1.2 V/km (scaled to the planning area) with a West-East orientation.

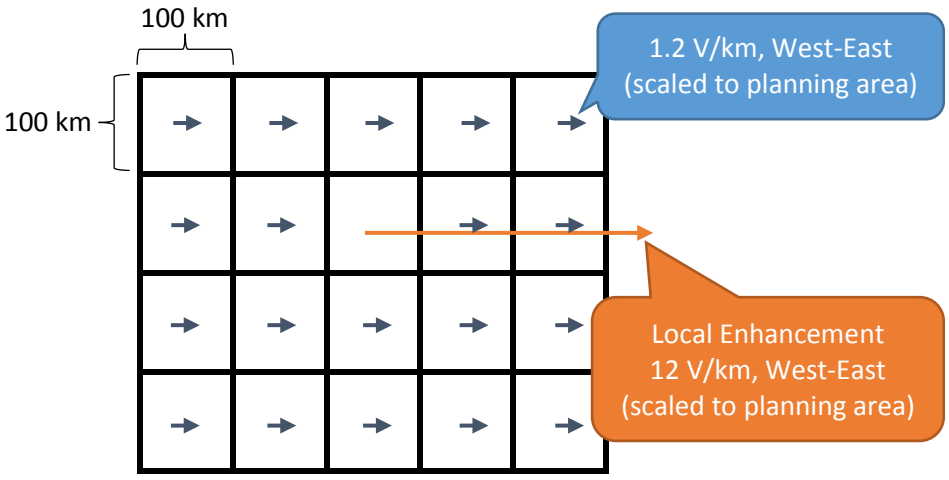


Figure 1. Schematic showing the boundaries to apply the supplemental event.

Chapter 9 – Requirement R8

Distribution of supplemental GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be considered by transmission planners.

The provision of information in Requirement R8, Part 8.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 10 – Requirement R9

The maximum effective GIC value provided in Part 9.1 is used for the supplemental thermal impact assessment. Only those transformers that experience an effective GIC value of 85 A or greater per phase require evaluation in Requirement R10.

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R9, Part 9.1.

The provision of information in Requirement R9 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 11 – Requirement R10

ERO Enterprise-Endorsed Implementation Guidance for conducting the thermal impact assessment of a power transformer is presented in the *Transformer Thermal Impact Assessment White Paper*, October 2016 [4].

Transformers are exempt from the supplemental thermal impact assessment requirement if the effective GIC value for the transformer is less than 85 A per phase, as determined by a GIC analysis of the System. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R10.

The supplemental threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the above referenced white paper and the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [5] for additional information.

Approaches for conducting the thermal impact assessment of transformers for the supplemental event are presented in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [6].

Thermal impact assessments for the supplemental event are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R8) and the Corrective Action Plan (R11) as necessary.

The provision of information in Requirement R10, Part 10.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 12 – Requirement R11

The requirement addresses directives in FERC Order No. 851 to develop and submit modifications to Reliability Standard TPL-007-2 (and TPL-007-3) to require corrective action plans for assessed supplemental GMD event vulnerabilities. This requirement is analogous to Requirement R7, such that CAPs are developed within one year from the completion of supplemental GMD Vulnerability Assessments and establishment of implementation deadlines after the completion of the CAP as follows:

- Two years for non-hardware mitigation; and
- Four years for hardware mitigation.

Part 11.4 requires entities to submit to the ERO with a request for extension when implementation of planned mitigation is not achievable within the deadlines established in Part 11.3. Examples of situations beyond the control of the responsible entity include, but are not limited to:

- Delays resulting from regulatory/legal processes, such as permitting;
- Delays resulting from stakeholder processes required by tariff;
- Delays resulting from equipment lead times; or
- Delays resulting from the inability to acquire necessary Right-of-Way.

Chapter 13 – Requirement R12

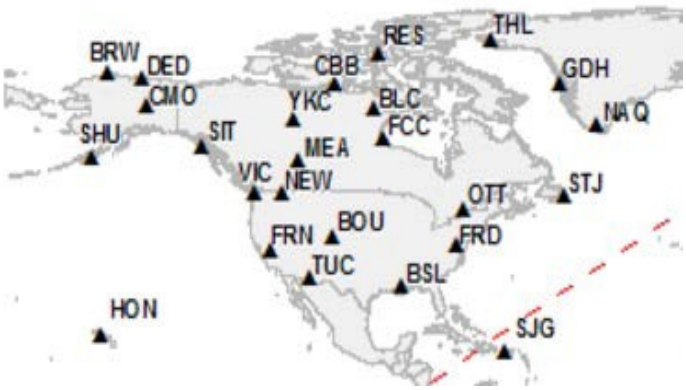
Responsible entities consider the following in developing a process for obtaining GIC monitor data:

- Monitor locations. An entity's operating process may be constrained by location of existing GIC monitors. However, when planning for additional GIC monitoring installations consider that data from monitors located in areas found to have high GIC based on system studies may provide more useful information for validation and situational awareness purposes. Conversely, data from GIC monitors that are located in the vicinity of transportation systems using direct current (for example subways or light rail) may be unreliable.
- Monitor specifications. Capabilities of Hall effect transducers, existing and planned, should be considered in the operating process. When planning new GIC monitor installations, consider monitor data range (for example -500 A through + 500 A) and ambient temperature ratings consistent with temperatures in the region in which the monitor will be installed.
- Sampling Interval. An entity's operating process may be constrained by capabilities of existing GIC monitors. However, when possible specify data sampling during periods of interest at a rate of 10 seconds or faster.
- Collection Periods. The process should specify when the entity expects GIC data to be collected. For example, collection could be required during periods where the Kp index is above a threshold, or when GIC values are above a threshold. Determining when to discontinue collecting GIC data should also be specified to maintain consistency in data collection.
- Data format. Specify time and value formats. For example, Greenwich Mean Time (GMT) (MM/DD/YYYY HH:MM:SS) and GIC Value (Ampere). Positive (+) and negative (-) signs indicate direction of GIC flow. Positive reference is flow from ground into transformer neutral. Time fields should indicate the sampled time rather than system or SCADA time if supported by the GIC monitor system.
- Data retention. The entity's process should specify data retention periods, for example one (1) year. Data retention periods should be adequately long to support availability for the entity's model validation process and external reporting requirements, if any.
- Additional information. The entity's process should specify collection of other information necessary for making the data useful, for example monitor location and type of neutral connection (for example three-phase or single-phase).

Chapter 14 – Requirement R13

Magnetometers measure changes in the earth's magnetic field. Entities should obtain data from the nearest accessible magnetometer. Sources of magnetometer data include:

- Observatories such as those operated by U.S. Geological Survey (USGS) and Natural Resources Canada (NRCan), see figure below for locations [7];



- Research institutions and academic universities; and
- Entities with installed magnetometers.

Entities that choose to install magnetometers should consider equipment specifications and data format protocols contained in the *INTERMAGNET Technical Reference Manual*, Version 4.6, 2012 [8].

References

1. FERC Order No. 779, https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Order779_GMD_RM12-22_20130516.pdf
2. FERC Order No. 830, https://www.nerc.com/filingsorders/us/FERCOrdersRules/E-4.pdf
3. FERC Order No. 851, https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/E-3_Order%20No%20851.pdf
4. Transformer Thermal Impact Assessment White Paper, ERO Enterprise-Endorsed Implementation Guidance, NERC, Atlanta, GA, October 28, 2016, https://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-007-1_Transformer_Thermal_Impact_Assessment_White_Paper.pdf
5. Screening Criterion for Transformer Thermal Impact Assessment White Paper, NERC, Atlanta, GA, October 2017, https://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/Screening_Criterion_Clean_2017_October_Clean.pdf
6. Transformer Thermal Impact Assessment White Paper, NERC, Atlanta, GA, October 2017, https://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/Thermal_Impact_Assessment_2017_October_Clean.pdf
7. International Real-Time Magnetic Observatory Network, http://www.intermagnet.org/index-eng.php
8. INTERMAGNET Technical Reference Manual, Version 4.6, 2012, http://www.intermagnet.org/publications/intermag_4-6.pdf

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justification

Project 2019-01 Modifications to TPL-007-3

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TPL-007-4. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justification for TPL-007-4, Requirement R1
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R1
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R2
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R2
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R3
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R3
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R4
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R4
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R5
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R5
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R6
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R6
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R7
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R7
The VSL did not substantively change from the previously FERC-approved TPL-007-3 Reliability Standard. In the Severe VSL, the word "have" was replaced with "develop" to more closely reflect the language of the Requirement.

VRF Justification for TPL-007-4, Requirement R8
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R8
The justification is provided on the following pages.

VRF Justification for TPL-007-4, Requirement R9
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R9
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R10
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R10
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R11
The justification is provided on the following pages.

VSL Justification for TPL-007-4, Requirement R11
The justification is provided on the following pages.

VRF Justification for TPL-007-4, Requirement R12

Requirement R12 was previously Requirement R11 in TPL-007-3. The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R12

Requirement R12 was previously Requirement R11 in TPL-007-3. The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R13

Requirement R13 was previously Requirement R12 in TPL-007-3. The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R13

Requirement R13 was previously Requirement R12 in TPL-007-3. The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSLs for TPL-007-4, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.

VSL Justifications for TPL-007-4, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs retain the VSLs from FERC-approved TPL-007-3 with the exception of removing one part of the lower VSL to reflect the removal of subpart 8.3 in TPL-007-3. As a result, the proposed VSLs do not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, 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	Each VSL is based on a single violation and not cumulative violations.

VSLs for TPL-007-4, Requirement R11			
Lower	**Moderate**	**High**	**Severe**
The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R11, Parts 11.1 through 11.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R11.

VSL Justifications for TPL-007-4, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance. Further, the VSLs are consistent with those assigned for Requirement R7, pertaining to Corrective Action Plans for benchmark GMD Vulnerability Assessments.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

VSL Justifications for TPL-007-4, Requirement R11	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-007-4, Requirement R11	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of High is being proposed for this requirement.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The proposed VRF is consistent among other FERC approved VRFs within the standard, specifically Requirement R7 pertaining to Corrective Action Plans for benchmark GMD Vulnerability Assessments.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High is consistent with Reliability Standard TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to include a Corrective Action Plan that addresses identified performance issues in the annual Planning Assessment.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The VRF of High is consistent with the NERC VRF Definition. Failure to develop a Corrective Action Plan that addresses issues identified in a supplemental GMD Vulnerability Assessment could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.

VRF Justifications for TPL-007-4, Requirement R11	
Proposed VRF	**Lower**
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	BES Cyber System Information Access Management		
Date Submitted:	March 1, 2019		
SAR Requester			
Name:	Alice Ireland		
Organization:	Tri-State Generation and Transmission Association		
Telephone:	(303) 254-3120	Email:	aireland@tristategt.org
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
While there is no direct benefit to the reliability of the BES, this initiative enhances BES reliability by creating increased choice, greater flexibility, higher availability, and reduced-cost options for entities to manage their BES Cyber System Information, by providing a secure path towards utilitzation of modern third-party data storage and analysis systems. In addition, the proposed project would clarify the protections expected when utilizing third-party solutions (aka cloud).			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
Clarifying the CIP requirements related to BES Cyber System Information access, to allow for alternative methods, such as encryption, to be utilized in the protection of BCSI.			
Project Scope (Define the parameters of the proposed project):			
CIP-004 and CIP-011			

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1]which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
CIP-004-6 Requirement R4 Part 4.1.3 needs to be modified so authorization and access to BCSI is clarified to focus on the BCSI and the controls deployed to limit access. In addition, the Standard should allow multiple methods for controlling access to BES Cyber System Information, rather than just electronic and physical access to the BES Cyber System Information storage location. For example, the focus must be on BCSI and the ability to obtain and make use of it. This is particularly necessary when it comes to the utilization of a third party's system (aka cloud). As currently drafted, the requirement is focused on access to the "storage location", and therefore does not permit methods such as encryption and key management to be utilized in lieu of physical/electronic access controls. This wording also does not explicitly permit any flexibility in the audit approach. In addition to modifying CIP-004-6 Requirement R4 Part 4.1.3, Part 4.4, Part 5.3 and CIP-011-2 Requirement R1 should also be evaluated for any subsequent impacts to the requirements, measures and/or the guidelines and technical basis.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Potential cost savings due to economies of scale and third party support.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Please see Section 4. Applicability of CIP-004-6 and CIP-011-2.
Do you know of any iconsensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus bulding activity.
An informal team, under the direction of the NERC Compliance Input Working Group, was assembled to review the use of encryption on BES Cyber System Information, and the impact on compliance, with a particular focus on such BES Cyber System Information being stored or utilized by a third party's system (aka cloud). This team met every two weeks during Dec. 2018 – Feb. 2019. The development of this SAR was supported by all team members. The team consisted of the following individuals:

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Requested information

Name	Company
Alice Ireland (lead)	Tri-State Generation and Transmission
David Vitkus	Tucson Electric Power
Eric Hull	SMUD
Marina Rohnow	Sempra Utilities/ San Diego Gas & Electric
Paul Haase	Seattle City Light
Richie Field	Hoosier Energy REC, Inc.
Rob Ellis	Tri-State Generation and Transmission
Steve Wesling	Tri-State Generation and Transmission
Toley Clague	Portland General Electric
Ziad Dassouki	ATCO Electric
Joseph Baxter	NERC
Lonnie Ratliff	NERC
Brian Kinstad	MRO
Holly Eddy	WECC
Kenath Carver	Texas Reliability Entity, Inc.
Michael Taube	MRO
Mike Stuetzle	NPCC
Morgan King	WECC
Shon Austin	Reliability First
Tremayne Brown	SERC

Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?

Project 2016-02 Modifications to CIP Standards

Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

When evaluating ways to modify the requirement, other standards and requirements were identified, which provide examples on possible paths forward. Of particular relevance are the following standards/requirements:

- CIP-006-6 Requirement R1 Part 1.10;
- CIP-010-2 Requirement R4, Attachment 1, Section 1.5;
- CIP-012-1 Requirement R1 (pending FERC approval).

Requested information
As a means to assist the SDT, several possible options for revision to CIP-004-6 Requirement R4 Part 4.1.3 have been drafted and provided below: EXAMPLE #1: [Delete 4.1.3 and create a new subrequirement in either CIP-004 or CIP-011, that would read something like this:] R4.X Process to prevent unauthorized access to BES Cyber System Information. The process shall include: 4.X.1. Identification of physical and electronic repositories utilized to store BES Cyber System Information. If electronic, indicate whether the repository is hosted by the Responsible Entity or a third-party and also whether it is in a virtual or non-virtual environment.; 4.X.2. Identification of security protection(s) used to prevent unauthorized access to BES Cyber System Information within each repository. Examples may include but are not limited to the following: • Encryption and key management, • Physical access management, • Electronic access management, • Data loss prevention techniques and rights management services. 4.X.3. The process to authorize access to BES Cyber System Information, based on need, as determined by the Responsible Entity, except for CIP Exceptional Circumstances; EXAMPLE #2: R4.1 Process to authorize based on need, as determined by the Responsible Entity, except for CIP Exceptional Circumstances: 4.1.1. Electronic access; 4.1.2. Unescorted physical access into a Physical Security Perimeter; 4.1.3. Physical access to physical BES Cyber System Information storage locations; 4.1.4. Physical access to unencrypted electronic BES Cyber System Information storage locations; 4.1.5. Electronic access to unencrypted electronic BES Cyber System Information storage locations; and 4.1.6. Electronic access to BES Cyber System Information encryption keys for encrypted BES Cyber System Information. EXAMPLE #3: R4.1 Process to authorize based on need, as determined by the Responsible Entity, except for CIP Exceptional Circumstances: 4.1.1. Electronic access; 4.1.2. Unescorted physical access into a Physical Security Perimeter; 4.1.3. Physical access to physical BES Cyber System Information storage locations; 4.1.4. Access to electronic BES Cyber System Information.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☐	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☒	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g. NPCC	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Revisions to Cyber Security – Supply Chain Controls Standard		
Date Submitted:	June 26, 2019		
SAR Requester			
Name:	Soo Jin, Manager of Standards Development		
Organization:	NERC		
Telephone:	404.831.4765	Email:	Soo.jin.kim@nerc.net
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
On October 18, 2018, the Federal Energy Regulatory Commission (FERC) issued Order No. 850 directing NERC to develop modifications to the Supply Chain Standards. In addition, NERC published a Cyber Security Supply Chain Risks report and recommendations for additional modifications to the Supply Chain Standards.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
This project will address the directives issued by FERC in Order No. 850 to modify the Supply Chain Standards. FERC directed NERC to submit modifications to address EACMSs, specifically those systems that provide electronic access control to high and medium impact BES Cyber Systems. FERC directed NERC to submit the modified Reliability Standard including the directed revisions for approval within 24 months from the effective date of Order No. 850. In addition, NERC also recommends revising the Supply Chain Standards to address Physical Access Control Systems (PACS) that provide physical access control (excluding alarming and logging) to high and medium impact BES Cyber Systems. The modifications to address PACS do not have a regulatory deadline, but will be addressed by this project.			

Requested information
Project Scope (Define the parameters of the proposed project):
This project will address the directives issued by FERC in Order No. 850. This project will also address NERC staff recommendation from the Supply Chain Report to address Physical Access Control Systems (PACS) that provide physical access control (excluding alarming and logging) to high and medium impact BES Cyber Systems.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1]which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
Consider recommendations to revise the Supply Chain Reliability Standards to include: (i) EACMSs, specifically those systems that provide electronic access control (excluding monitoring and logging) to high and medium impact BES Cyber Systems; and (ii) PACSs that provide physical access control (excluding alarming and logging) to high and medium impact BES Cyber Systems.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impact is unknown at this time. However, a question will be asked during the SAR comment period to ensure all aspects are considered.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
Submitter asserts there are no unique characteristics associated with BES facilities that will be impacted by this proposed standard development project.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Distribution Provider, Generator Owner, Generator Operator
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
No
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
Project 2016-02 Modifications to CIP Standard
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
None at this time

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☐	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☒	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
	None identified

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	PRC-005-6 applicability to AVR protective functions		
Date Submitted:	5/9/2019		
SAR Requester			
Name:	Alison Mackellar		
Organization:	North American Generator Forum (NAGF)		
Telephone:	630-657-2817	Email:	alison.mackellar@exeloncorp.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
PRC-005-6 needs to be revised to provide clear guidance on the scope of applicability to Automatic Voltage Regulator (AVR) protective functions. Without clear applicability the industry is struggling with how to implement PRC-005-6 and what testing is acceptable to meet the required maintenance activities prescribed by PRC-005-6.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
Provide clear, unambiguous applicability of PRC-005-6 to AVR protective functions and the specificity needed for the industry to consistently identify and implement the required maintenance activities.			
Project Scope (Define the parameters of the proposed project):			
Revise PRC-005-6 to clearly define the applicability of Protection Systems associated with AVR protective functions. In addition, revise the PRC-005-6 Supplementary Reference and FAQ to provide additional guidance related to AVR protective functions and acceptable methods of testing to meet PRC-005-6 required maintenance activities.			

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
1. Revise PRC-005-6 to add a new section under Facilities to clearly delineate the applicability of Protection Systems associated with AVR protective functions. This new section needs to clearly limit the scope of the AVR protective functions to those elements that open a breaker directly or via lockout or tripping auxiliary relays. 2. Revise the PRC-005-6 Supplementary Reference and FAQ Section 15 to provide a more detailed description of the applicability of AVR protective functions and to provide acceptable methods of testing to meet PRC-005-6 required maintenance activities.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Unknown
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
Only applicable to a Generator Owner that owns a synchronous generating unit with an installed digital AVR
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Generator Owner (GO)
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The NAGF and the NEI worked together to generate this SAR and have communicated the issue in advance to NERC.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g., NPCC	None

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff	☐ Final SAR endorsed by the SC
☐ Draft SAR presented to SC for acceptance	☐ SAR assigned a Standards Project by NERC
☐ DRAFT SAR approved for posting by the SC	☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Modification to PER-003-2		
Date Submitted:	09 July 2019		
SAR Requester			
Name:	Personnel Certification and Governance Committee (Chair – Mike Anderson)		
Organization:	NERC		
Telephone:	(614) 413-2311	Email:	mcanderson@aep.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Enhanced BES Reliability			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
Referencing the PCGC's "One System Operator Certification credential" whitepaper, all System Operators would hold the same Certification credential. This better serves reliability by ensuring all System Operators, regardless of their company's registration or credential of choice, have the same base knowledge. This knowledge is demonstrated through the System Operator Certification process.			
Project Scope (Define the parameters of the proposed project):			
Modification of PER-003-2 through the Standards Development Process			

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Revise PER-003-2 to address one credential is required, not the current four credentials. PER-005 did not exist at the inception of system operator certification. PER-003-2 is a personal certification of minimal knowledge and skills; whereas PER-005 addresses more specific reliability related tasks for entity qualifications/requirements. To address any potential gaps concerning the misconception of applicable areas of competency, please consider making a stronger tie between the revised PER-003-2 to PER-005. It is still important to maintain the independence of each Standard.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Minimal cost impact to industry as bundled in the PCGC's budget recovered through existing exam and renewal fees.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
N/A
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Reliability Coordinator, Transmission Operator, Balancing Authority
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
Industry circulated "One Credential" whitepaper and associated comments/responses from the PCGC
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
None
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☒	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g., NPCC	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff	☐ Final SAR endorsed by the SC
☐ Draft SAR presented to SC for acceptance	☐ SAR assigned a Standards Project by NERC
☐ DRAFT SAR approved for posting by the SC	☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk

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%			
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%			

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
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%			
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%			

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
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%			
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%			

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
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%			
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%			

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
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		
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		

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
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%			
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		

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
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%			
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		

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
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%			
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		

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
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		
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		

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
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%			
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		

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
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%			
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		

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
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
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: %			

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
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.]		[illegible] 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%			
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.

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
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%			
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%			

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
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		
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	

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
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	
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	

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	
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.	
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.	Last RSC Meeting
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 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	Quorum: 80.73%/80.49%/80.00%/80.24%/80.24%/80.49%/80.24%/78.29% Approval: 35.67%/80.76%/76.24%/78.41%/85.32%/49.42%/82.55%/78.58%	CIP-003 No CIP-004 Yes CIP-006 Yes CIP-007 Yes CIP-009 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 Testing - Phase 3	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%	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			

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: 76.12%/74.23%/75.67%/85.49%/75.96%/78.67%/48.73%/78.87%/87.03%/93.34%/90.13%	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%	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		
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		

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
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		
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		

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
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		
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%	Affirmative--7/24/15		

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
						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% Approval: 87.36%	Affirmative--9/18/15		
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%	Affirmative--3/10/16		

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: 78.87%			
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% Approval: 80.36%/93.43%	Affirmative--3/10/16		
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		

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
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% Approval: 81.30%/87.87%/86.75%/86.47%	Affirmative--1/23/17		
573	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Initial Ballot	2/24/2017	3/6/2017	Quorum: 87.13% Approval: 10.36%	Abstain--3/2/17		
574	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Final Ballot	1/24/2017	2/2/2017	Quorum: 84.46% Approval: 93.80%	Affirmative--1/4/17		
575	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7(i) Implementation Plan and 2 Definitions	Final Ballot	1/30/2017	2/8/2017	Quorum: 86.58%/85.48%/86.03%/85.48% Approval: 78.55%/86.00%/85.81%/85.54%	Affirmative--1/23/17		
576	SPM	Revisions to the NERC Standards Process Manual	Initial Ballot	4/24/2017	5/3/2017	Quorum: 78.21% Approval: 64.72%			
577	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Additional Ballot	6/6/2017	6/15/2017	Quorum: 76.02%/76.02%/77.21% Approval: 89.84%/82.92%/88.64%	Affirmative--6/8/17		
578	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Final Ballot	7/11/2017	7/20/2017	Quorum: 81.59%/81.33%/82.84% Approval: 88.79%/81.40%/84.19%	Affirmative--6/8/17		
579	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	Initial Ballot	8/2/2017	8/11/2017	Quorum: 79.87% Approval: 72.67%	Affirmative--8/3/17		
580	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Initial Ballot	8/29/2017	9/8/2017	Quorum: 80.45% Approval: 78.79%	Affirmative--9/1/17		
581	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1 Control Center Communication Networks	Initial Ballot	8/14/2017	9/12/2017	Quorum: 80.00% Approval: 42.74%	Affirmative--9/1/17		
582	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Initial Ballot	9/8/2017	10/23/2017	Quorum: 82.71% Approval: 30.50%	Abstain--10/18/17		
583	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	Final Ballot	10/20/2017	10/30/2017	Quorum: 88.74% Approval: 73.35%	Affirmative--8/3/17		
584	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Initial Ballot	9/14/2017	10/30/2017	Quorum: 85.40% Approval: 66.78%	Affirmative--10/30/17		
585	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Initial Ballot	11/3/2017	11/13/2017	Quorum: 87.01%/86.90%/86.90%/85.57%/85.85 Approval: 58.12%/63.17%/56.55%/76.40%/68.59%	Affirmative--11/10/17		
586	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	11/20/2017	12/11/2017	Quorum:77.10% Approval: 63.91%	Affirmative--12/4/17		
587	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Additional Ballot	10/30/2017	12/13/2017	Quorum: 81.73% Approval: 88.25%	Affirmative--12/4/17		
588	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Final Ballot	1/9/2018	1/18/2018	Quorum: 82.69% Approval: 89.46%	Affirmative--12/4/17		
589	Project 2017-02	Project 2017-02 Modifications to Personnel Performance, Training and Qualifications	Initial Ballot	2/26/2018	3/7/2018	Quorum: 80.93%/81.27% Approval: 97.50%/98.91%	Affirmative--3/2/18		
590	Project 2017-02	Project 2017-02 Modifications to Personnel Performance, Training and Qualifications	Final Ballot	4/3/2018	4/12/2018	Quorum: 84.82%/84.86% Approval: 96.64%/97.88%	Affirmative--3/2/18		
591	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Additional Ballot	2/23/2018	4/23/2018	Quorum: 80% Approval: 26.44%	Affirmative--4/16/18		
592	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Additional Ballot	3/16/2018	4/30/2018	Quorum: 79.50% Approval: 93.31%	Affirmative--4/25/18		
593	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	3/16/2018	4/30/2018	Quorum:78.06% Approval: 83.71%	Affirmative--4/25/18		

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
594	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1 Control Center Definition and Implementation Plan	Initial Ballot	3/16/2018	4/30/2018	Quorum: 81.33%/81.54% Approval: 46.71%/37.98%	Negative--4/25/18		
595	Project 2017-06	Project 2017-06 Modifications to BAL-002-2	Initial Ballot	4/27/2018	5/8/2018	Quorum: 81.82% Approval: 80%	Abstain--5/7/17		
596	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	5/18/2018	7/3/2018	Quorum: 75.16% Approval: 68.45%	Affirmative--6/29/18		
597	Project 2017-06	Project 2017-06 Modifications to BAL-002-2	Final Ballot	7/5/2018	7/16/2018	Quorum: 84.42% Approval: 71.85%	Abstain--5/7/17		
598	SPM	Revisions to the NERC Standards Process Manual	Additional Ballot	7/31/2018	8/9/2018	Quorum: 80.34% Approval: 81.95%	Affirmative--8/7/18		
599	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Final Ballot	8/3/2018	8/13/2018	Quorum:81.55% Approval: 72..55%	Affirmative--4/25/18		
600	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Additional Ballot	9/5/2018	9/14/2018	Quorum: 75.59% Approval: 69.07%	Affirmative--9/5/18		
601	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Initial Ballot	9/28/2018	10/9/2018	Quorum: 78.59% Approval: 55.89%	Affirmative--10/5/18		
602	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-003-8	Initial Ballot	9/28/2018	10/9/2018	Quorum: 78.77% Approval: 90.06%	Affirmative--10/5/18		
603	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Additional Ballot	10/8/2018	10/17/2018	Quorum: 83.65%/84.08%/83.77%/84.82%/82.43%/82.11%/84.08%/83.60%/83.12%/80.98%/83.28% Approval: 67.65%/67.46%/53.22%/77.07%/59.02%/59.79%/75.07%/69.27%/71.98%/69.93%/82.26%	Affirmative--10/12/18		
604	Project 2018-02	Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	Initial Ballot	10/18/2018	10/22/2018	Quorum: 81.17% Approval: 20.02%	Reject--10/22/18		
605	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Final Ballot	10/11/2018	10/22/2018	Quorum: 86.39% Approval: 66.69%	Affirmative--9/5/18		
606	SPM	Revisions to the NERC Standards Process Manual	Final Ballot	10/7/2018	10/29/2018	Quorum: 85.96% Approval: 81.61%	Affirmative--8/7/18		
607	Project 2018-01	Project 2018-01 Canadian-specific Revisions to TPL-007-2	Initial Ballot	11/6/2018	11/15/2018	Quorum: 77.54%/79.10% Approval: 100%/100%	Affirmative--11/6/18		
608	Project 2018-02	Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	Additional Ballot	11/20/2018	11/29/2018	Quorum: 94.44% Approval: 75.54%	Affirmative--11/20/18		
609	Project 2018-01	Project 2018-01 Canadian-specific Revisions to TPL-007-2	Final Ballot	11/29/2018	12/10/2018	Quorum: 80.43%/82.09% Approval: 100%/100%	Affirmative--11/6/18		
610	Project 2017-01	Project 2017-01 Modifications to BAL-003-1.1	Initial Ballot	1/8/2019	1/17/2019	Quorum: 92.02%/91% Approval: 96.41%/99.04%	Affirmative--1/14/19		
611	Project 2018-02	Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	Final Ballot	1/15/2019	1/22/2019	Quorum: 96.30% Approval: 77.89%	Affirmative--11/20/18		
612	Project 2018-03	Project 2018-03 Standards Efficiency Review Retirements	Initial Ballot	4/3/2019	4/12/2019	Quorum: 86.75%/87.96%/87.80%/87.58%/87.58%/87.50%/87.58%/87.34%/87.46%/86.45%/87.34%/86.77%/87.17%/87.17%/86.89%/85.71%/85.67%/86.39%	Affirmative--4/10/19 for all standards except three. Negative--4/10/19 on following standard: BRC-004-5(i), INT-010-		

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: 96.18%/98.88%/97.41%/97.79%/98.51%/89.75%/98.53%/96.60%/95.96%/96.60%/95.80%/98.95%/96.45%/96.54%/95.90%/88.42%/98.96%/97.69%	Negative--4/10/19 on following standard: PRC-004-5(i), INT-010-2.1 and FAC-0008-3		
613	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-003-8	Final Ballot	4/18/2019	4/29/2019	Quorum: 83.64% Approval: 91.44%	Affirmative--10/5/18		
614	Project 2018-03	Project 2018-03 Standards Efficiency Review Retirements	Final Ballot	4/3/2019	4/12/2019	Quorum: 90.22%/90.97%/90.85%/90.94%/90.94%/90.88%/90.60%/90.26%/90.43%/90.32%/90.26%/90.65%90.13%/90.13%/89.84%/90.06%/90.03%/89.56% Approval: 95.74%/86.66%/85.94%/96.64%/97.22%/90.19%/97.19%/95.47%/94.63%/94.34%/94.69%/96.59%95.28%/95.41%94.55%/87.12%/97.75%/96.57%	Affirmative--4/10/19 for all standards except three.		
615	Project 2018-04	Project 2018-04 Modifications to PRC-024-2	Initial Ballot	5/22/2019	5/31/2019	Quorum: 88.08% Approval: 52.28%	Abstain--5/29/19		
616	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Additional Ballot	6/3/2019	7/17/2019	Quorum: 85.40% Approval: 87.39%	Affirmative--7/15/19		
617	Project 2019-01	Project 2019-01 Modifications to TPL-007-3	Initial Ballot	8/30/2019	9/9/2019	Quorum: 91.44% Approval: 88.81%	Affirmative--9/5/19		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments

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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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	
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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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	
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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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	
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	

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
			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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

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	

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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	

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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	
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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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	CIP-002 to CIP-011	Formal	06/02/14	07/17/14	Yes 7/16/14

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		– Cyber Security Standards					
225	Project 2015-2017	Project 2015-2017 Reliability Standard Development Plan		Informal		7/21/14	Yes 7/21/14
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-	TOP-001-3 TOP-002-4	Formal	08/6/14	09/19/14	Yes 9/22/14

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		IRO Reliability Standards	TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1				
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
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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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 for Dispersed Generation Resources	PRC-001-1.1 PRC-019-2 PRC-024-1	Formal	11/05/14	12/23/14	Yes 12/22/14
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	PRC-005-5	Informal	12/22/14	1/20/15	Yes 1/22/15

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		Generation Resources					
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
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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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-based Controls	BAL-002-2	Formal	7/7/15	8/20/15	Yes 8/20/15
282	Project 2010-	Phase 2 of Balancing Authority	BAL-004-0	Survey	8/12/15	8/25/15	Yes 8/25/15

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	14.2.2	Reliability-based Controls: Time Error Correction					
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

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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 2016-02	Modifications to CIP Standards	SAR	Informal	3/23/16	4/21/16	Yes 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	Emergency	EOP-004-4	Formal	7/25/16	9/8/16	Yes 9/8/16

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	2015-08	Operations					
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 2016-02	Modifications of CIP Standards	CIP-003-TCA	Informal	11/1/16	11/18/16	Yes 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	SPM	Formal	3/20/17	5/3/17	Yes 5/3/17

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		Processes Manual					
336	Project 2015-10	Single Points of Failure	TPL-001-5	Informal	4/25/17	5/24/17	Yes 5/24/17
337	Project 2016-03	Cyber Security Supply Chain Risk Management	CIP-005-6 CIP-010-3 CIP-013-1	Formal	5/2/17	6/15/17	Yes 6/15/17
338	Project 2017-01	Modifications to BAL-003-1.1 SAR	BAL-003-1.1	Formal	6/19/17	7/18/17	Yes 7/18/17
339	Project 2017-06	Modifications to BAL-002-2 SAR	BAL-002-2	Informal	6/20/17	7/20/17	Yes 7/20/17
340	Project 2017-02	Modifications to Personnel Performance, Training and Qualifications Standards	PER-003-1 PER-004-2	Informal	6/21/17	7/24/17	Yes 7/24/17
341	2018-2010	Reliability Standards Development Plan		Formal	6/22/17	7/25/17	Yes 7/26/17
342	Standards Grading	Periodic Review Standing Review Team	Standards Grading	Informal	6/19/17	8/2/17	Yes 8/2/17
343	Project 2013-03	Geomagnetic Disturbance Mitigation	TPL-007-2	Formal	6/28/17	8/11/17	Yes 8/11/17
344	Project 2017-07	Alignment with Registration	Registration	Formal	8/1/17	8/30/17	Yes 8/30/17
345	Project 2017-07	Alignment with Registration	MOD-032-1 SAR	Formal	8/1/17	8/30/17	Yes 8/30/17
346	Reliability Guideline	Area Control Error Diversity Interchange Process	ACE Process	Formal	7/18/17	8/31/17	Yes 8/31/17
347	Project 2016-04	Modifications to PRC-025-1	PRC-025-2	Formal	7/25/17	9/7/17	Yes 9/7/17
348	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	7/27/17	9/11/17	Yes 9/11/17
349	Project 2016-02	Modifications to CIP Standard	Technical Rationale and Justification for CIP-012-1	Informal	8/14/17	9/12/17	Yes 9/12/17
350	Project 2016-02	Modifications to CIP Standard	Definition of Control Center	Informal	8/14/17	9/12/17	Yes 9/12/17
351	Project 2015-10	Single Points of Failure	TPL-001-5	Formal	9/8/17	10/23/17	Yes 10/23/17
352	Project 2016-02	Modifications to CIP Standard	CIP-002-6	Formal	9/14/17	10/30/17	Yes 10/30/17
353	Project 2015-09	Establish and Communicate System Operating Limits	Proposed Definitions of System Operating Limit (SOL) and SOL Exceedance	Informal	9/29/17	10/30/17	Yes 10/30/17
354	Project 2016-02	Modifications to CIP Standard	Virtualization	Informal	10/6/17	11/2/17	Yes 11/2/17
355	Project 2015-09	Establish and Communicate System Operating	FAC-010 FAC-011 FAC-014	Formal	9/29/17	11/13/17	Yes 11/13/17

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		Limits					
356	Project 2017-01	Modifications to BAL-003-1.1	SAR	Formal	11/2/17	12/1/17	Yes 12/1/17
357	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	10/27/17	12/11/17	Yes 12/11/17
358	Project 2016-02	Modifications to CIP Standard	Technical Rationale/Justification	Informal	11/20/17	12/11/17	Yes 12/11/17
359	Project 2017-03	FAC-008-3 Periodic Review	FAC-008-3	Formal	10/30/17	12/13/17	Yes 12/13/17
360	Project 2016-04	Modifications to PRC-025-1	PRC-025-1	Formal	10/30/17	12/13/17	Yes 12/13/17
361	Project 2017-07	Alignment with Registration	SAR	Formal	12/11/17	1/9/18	Yes 1/9/18
362	Project 2017-05	NUC-001-3	NUC-001-3	Formal	12/15/17	1/29/18	Yes 1/29/18
363	Project 2017-04	INT Periodic Review	INT-004-3.1 INT-006-4 INT-009-2.1 INT-010-2.1	Formal	1/10/18	2/23/18	Yes 2/23/18
364	Project 2017-07	Standards Alignment with Registration	Multiple Standards	Formal	2/1/18	3/2/18	Yes 3/2/18
365	Project 2017-02	Modifications to Personnel Performance, Training and Qualifications (PER) Standards	PER-003-1 PER-004-2	Formal	1/22/18	3/7/18	Yes 3/7/18
366	Project 2015-10	Single Points of Failure	TPL-001-5	Formal	2/23/18	4/23/18	Yes 4/23/18
367	Project 2018-01	Canadian-specific Revisions to TPL-007-2 SAR	TPL-007-2 SAR	Formal	3/30/18	4/30/18	Yes 4/30/18
368	Project 2016-02	Modifications to CIP Standard	CIP-002-6	Formal	3/16/18	4/30/18	Yes 4/30/18
369	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	3/16/18	4/30/18	Yes 4/30/18
370	Project 2016-02	Modifications to CIP Standard	Control Center Definition and Implementation	Formal	3/16/18	4/30/18	Yes 4/30/18
371	Standards Grading	2018 Periodic Review Standing Review Team	Standard Grading	Informal	5/14/18	6/28/18	Yes 6/28/18
372	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	5/18/18	7/3/18	Yes 7/2/18
373	SER	Standard Efficiency Review	SAR	Informal	6/7/18	7/10/18	Yes 7/10/18
374	Project 2016-02	Modifications to CIP Standard	CIP-002-5.1a SAR	Informal	6/14/18	7/13/18	Yes 7/13/18
375	Project 2016-02	Modifications to CIP Standard	CIP-003-7 SAR Order 843	Informal	6/14/18	7/13/18	Yes 7/13/18
376	SPM	Standards Processes Manual	SPM	Formal	6/25/18	8/9/18	Yes 8/9/18

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
377	Project 2018-01	Canadian-specific Revisions to TPL-007-2	TPL-007-2	Informal	8/10/18	9/6/18	Yes 9/6/18
378	Project 2018-02	Modifications to CIP-008 Cyber Security Incident Reporting SAR	CIP-008-5	Informal	8/10/18	9/10/18	Yes 9/10/18
379	Project 2015-10	Single Points of Failure	TPL-001-5	Formal	7/30/18	9/14/18	Yes 9/14/18
380	Functional Model Advisory Group	Functional Model Advisory Group	Functional Model Advisory Group	Informal	8/3/18	9/19/18	Yes 9/17/18
381	Project 2017-01	Modifications to BAL-003-1.1	BAL-003-1.1	Informal	9/6/18	9/20/18	Yes 9/20/18
382	SER	Standard Efficiency Review	SAR	Formal	8/28/18	9/26/18	Yes 9/26/18
383	Project 2016-02	Modifications to CIP Standards	CIP-002-6	Formal	8/23/18	10/9/18	Yes 10/9/18
384	Project 2016-02	Modifications to CIP Standards	CIP-003-8	Formal	8/23/18	10/9/18	Yes 10/9/18
385	Project 2015-09	Establish and Communicate System Operating Limits	FAC-010 FAC-011 FAC-014	Formal	8/24/18	10/17/18	Yes 10/17/18
386	Project 2018-02	Cyber Security – Incident Reporting and Response Planning	CIP-008-6	Formal	10/3/18	10/22/18	Yes 10/22/18
387	Project 2018-01	Canadian-specific Revisions to TPL-007-2	TPL-007-2	Formal	10/2/18	11/15/18	Yes 11/15/18
388	Project 2018-02	Cyber Security – Incident Reporting and Response Planning	CIP-008-6	Formal	11/15/18	11/29/18	Yes 11/29/18
389	Project 2016-02	Modifications to CIP Standards	Virtualization	Informal	11/2/18	12/18/18	Yes 12/18/18
390	Project 2017-01	Modifications to BAL-003-1.1	BAL-003-1.1	Formal	12/4/18	1/17/19	Yes 1/17/19
391	Project 2018-04	Modifications to PRC-024-2	PRC-024-2	Formal	12/19/18	1/18/19	Yes 1/18/19
392	Standard Efficiency Review	Standard Efficiency Review	SER Phase 2 Concepts Survey	Informal	2/22/19	3/22/19	Yes 3/22/19
393	Project 2019-01	Modifications to TPL-007-3	TPL-007-3	Informal	2/25/19	3/26/19	Yes 3/26/19
394	Project 2018-03	Standard Efficiency Review Retirements	FAC-008-4 INT-006-5 INT-009-3 IRO-002-6 PRC-004-6 TOP-001-5	Formal	2/27/19	4/12/19	Yes 4/12/19

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
			VAR-001-6 FAC-013-2 INT-004-3.1 INT-010-2.1 MOD-001-1a MOD-004-1 MOD-008-1 MOD-020-0 MOD-028-2 MOD-029-2a MOD-030-3 MOD-001-2				
395	Project 2019-02	BES Cyber System Information Access Management	CIP-004-6	Formal	3/28/19	4/26/19	Yes 4/26/19
396	Project 2018-04	Modifications to PRC-024-2	PRC-024-2	Formal	4/17/19	5/31/19	Yes 5/31/19
397	Project 2016-02	Modifications to CIP Standards	Virtualization White Paper	Informal	5/30/19	6/28/19	Yes 6/28/19
398	Project 2016-02	Modifications to CIP Standards	CIP-002-6	Formal	6/3/19	7/17/19	Yes 7/17/19
399	Project 2018-04	Modifications to PRC-024-2	PRC-024-2	Informal	6/27/19	7/26/19	Yes 7/26/19
400	Project 2019-03	Cyber Security Supply Chain Risks	CIP-005-6 CIP-010-3 CIP-013-1	Informal	7/2/19	8/1/19	Yes 8/1/19
401	SER	CIP SER	CIP Standards	Formal	7/3/19	8/26/19	Yes 8/26/19
402	Project 2019-04	Modifications to PRC-005-6	PRC-005-6 SAR	Formal	7/30/19	8/28/19	Yes 8/28/19
403	Project 2019-05	Modifications to PER-003-2	PER-003-2	Informal	8/1/19	8/30/19	Yes 8/30/19
404	Project 2016-02	Modifications to CIP Standards	CIP-005	Informal	8/9/19	9/26/19	Yes 9/26/19
405	EMP	Electromagnetic Pulses Task Force Draft Strategic Recommendation	EMP	Informal	8/30/19	9/30/19	Yes 9/30/19

RSC Meeting #19-4, Agenda Item 6.3: Comment History

(As of 10/2/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted

Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."

NPCC, Inc.

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

February 15th, 2019

NPCC Full and General Members:

In accordance with the FERC approved NPCC Regional Standard Processes Manual, revisions were performed for the NPCC Regional Standard PRC-006-NPCC-02 Automatic Underfrequency Load Shedding. The Standard was posted for three open process comment periods and a pre-ballot review. A ballot was then conducted which closed at 23:59PM on February 10th, 2019.

The results of the ballot were as follows:

Quorum: 80.95% of the Total Registered NPCC General and Full Members Representatives
Approval: 76%

Requisite approval was attained for the ballot therefore a recommendation for final NPCC Regional approval will be sent to the NPCC Board of Directors for consideration at their meeting on May 1st, 2019.

Contingent upon the approval of the NPCC BOD, the proposal to approve PRC-006-NPCC-02 will be submitted to the NERC Board of Trustees for their consideration and adoption at their August 14-15, 2019 meeting. NERC and NPCC will then develop filings for the FERC and applicable provincial authorities for their review and final approval.

Voting was conducted electronically and the full record for the standard may be viewed, after signing in, at:

https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=122

Thank you for your participation in the development of this important Standard to ensure the reliablity objectives of NPCC.

Ruida Shu
Northeast Power Coordinating Council, Inc.
Manager, Reliability Standards
Main: 212-840-1070
Direct: 917-934-7976
Fax: 212-302-2782
Email: rshu@npcc.org

	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	**17**	**17**	**0**		**17**	**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	1			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 Hampshire Transmission, LLC	1	1			1		
New York Power Authority	1	1			1		
New York State Electric & Gas Corporation	1	1			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	**21**	**17**	**2**	**19**	**0**	**0**
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 Brunswick Power Corporation	1	1		1		
New York Power Authority	1	1		1		
Orange and Rockland Utilities, Inc	1	1		1		
Princeton Municipal Light Department	1					
Shrewsbury Electric & Cable Operations	1	1		1		
Sterling Municipal Light Department	1	1		1		
Toronto Hydro Electric System Ltd.	1	1		1		
Vermont Electric Cooperative, Inc.	1					
Wakefield Municipal Gas and Light Department	1	1		1		
Westfield Gas & Electric	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 4, Generator Owners	**20**	**16**	**0**		**10**	**4**	**2**
Bruce Power L.P.	1						
Consolidated Edison Company of New York, Inc.	1	1			1		
Covanta Energy	1	1				1	
Dominion Resources, Inc.	1	1			1		
Eastern Generation LLC	1	1					1
Entergy Nuclear Northeast, Inc	1	1			1		
Exelon Generation Company, LLC	1						
First Wind Operations & Maintenance	1						
Long Island Power Authority	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	1				1	
Talen Energy Supply, LLC	1	1				1	
TransCanada	1	1			1		
Vistra Energy Corp	1	1			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	**12**	**9**	**0**		**8**	**0**	**1**
Brookfield Power Corporation	1	1			1		
Consolidated Edison Company of New York, Inc.	1	1			1		
Consolidated Edison Energy/Development	1						
HQ Energy Marketing Inc.	1	1			1		
H.Q. Energy Services (U.S.) Inc.	1	1			1		
Long Island Power Authority	1	1			1		
Massachusetts Municipal Wholesale Electric Company	1	1			1		
Nalcor Energy	1						
New York Power Authority	1	1			1		
Nexus Energy Inc.	1	1					1
Shell Energy North America	1						
Utility Services Inc.	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 6, State and Provincial Reg. and Govt. Au	**5**	**3**	**0**		**3**	**0**	**0**
Long Island Power Authority	1	1			1		
Maine Public Utilities Commission	1	1			1		
New Hampshire Public Utilities Commission	1						
New York Power Authority	1	1			1		
New York State 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	**25**	**16**	**0**		**14**	**0**	**2**
4g Technologies, LP	1						
Abloy Security, Inc.	1	1			1		
AESI Acumen Engineered Solutions Internaiontal Inc.	1	1			1		
Ascendant Energy Solutions, Inc.	1						
Casimir Systemics LLC	1	1			1		
Ciufo & Cooperberg Consulting Inc.	1	1			1		
DataCapable, Inc.	1						
David Kiguel	1	1			1		
ERLPhase Power Technologies	1	1			1		
GDS Associateds, Inc.	1	1			1		
Genieall	1						
International Business Machines Corporation	1						
Ironhouse Inc.	1						
McCoy Power Consultants, Inc.	1	1			1		
Network & Security Technologies, Inc.	1	1					1
New Power Technologies, Inc	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		
Sund Technologies, LLC	1						
TRC Solutions	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**	17	17	0	17	1.00
2	**Reliability Coordinators**	5	5	0	5	1.00
3	**TDUs, Dist. And LSE**	21	17	2	19	0.90
4	**Generator Owners**	20	16	0	16	0.80
5	**Marketers, Brokers, Aggragators**	12	9	0	9	0.75
6	**Customers- large and small**	5	3	0	3	0.60
7	**State and Provincial Reg. and Govt. Authorities**	25	16	0	16	0.64
		105	83	2	85	

Electronic Vote Quorum= at least 2/3 of the Total Registered

Quorum Present? **YES**

Determine if Motion or Item Passes

Sector	Sector Name	Total Registered	Sector % Attending	Affirmative # of Votes	Affirmative Fraction	Negative # of Votes	Negative Fraction	Abstain # of Votes	Votes Cast Total (-Abstentions)	Sector has Voted(1-Y, 0-N)
1	**Transmission Owners**	17	1.00	17	1.000	0	0.000	0	17	1
2	**Reliability Coordinators**	5	1.00	5	1.000	0	0.000	0	5	1
3	**TDUs, Dist. And LSE**	21	0.90	19	1.000	0	0.000	0	19	1
4	**Generator Owners**	20	0.80	10	0.714	4	0.286	2	14	1
5	**Marketers, Brokers, Aggragators**	12	0.75	8	1.000	0	0.000	1	8	1
6	**Customers- large and small**	5	0.60	3	1.000	0	0.000	0	3	1
7	**State and Provincial Reg. and Govt. Authorities**	25	0.64	14	1.000	0	0.000	2	14	1
	Totals	105		76	6.714	4	0.286	5	80	7

Sum of Affirmative/Number of Sectors that Voted MUST BE AT LEAST 2/3 to pass 0.959

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:

Quintin Lee
Program Manager - Reliability Compliance
Eversource Energy
780 North Commercial Street
Manchester, NH 03101
Office: (603) 634-3579
Cell: (603) 315-9010
Email: quintin.lee@eversource.com

Co-Vice Chairman:

Michael Jones
Manager, Reliability Standards and Policy
National Grid
40 Sylvan Road
Waltham, Massachusetts 02451
Tel. (781) 907-2404
Email: michael.jones@nationalgrid.com

Sector 1 - Transmission Owners

Hydro One Networks, Inc.

Primary
Paul Malozewski, P. Eng., MBA, PMP
Senior Manager – Reliability Standards and Compliance Assurance
Tel. 416-345-5005
Email: paul.malozewski@hydroone.com

Alternate
Payam Farahbakhsh, M. Eng, P. Eng.
Senior Network Management Engineer – Reliability Standards and Compliance Assurance
Tel. (416) 345-5484
Email: Payam.Farahbakhsh@HydroOne.com

Consolidated Edison Company of New York, Inc.

Primary
Michael Forte
Chief Transmission Planning Engineer
Tel. (212) 460-3416
Fax (212) 529-1130
Email: fortem@coned.com

Alternate
Martin Paszek
Manager, System Performance
Tel. (212) 460-6415
Fax (212) 529-1130
Email: paszekm@coned.com

National Grid

Primary
John Hastings
Lead Analyst, Transmission Control Center – NY
7437 Henry Clay Blvd HCB-3
Liverpool, NY 13088
National Grid, US
Tel. (315) 460-4139
Email: John.Hastings2@nationalgrid.com

Alternate

New Brunswick Power Corporation

Primary
Laura Mcleod, P.Eng.
Corporate Compliance
515 King St, Fredericton NB, Canada E3B 5G4
Tel. (506) 458-6662
Email: laura.mcleod@nbpower.com

Alternate
Nurul Abser
Engineer IV, Compliance
Tel. (506) 458-3964
Cell. (506 238-3624
Email: NAbser@nbpower.com

The United Illuminating Company

Primary
Michele Tondalo
Lead Analyst – NERC Compliance (O&P)
180 Marsh Hill Road
Orange, Connecticut 06477
Tel. (203) 499-2542
Email: Michele.Tondalo@uinet.com

Alternate
Kristina Henderson, CPESC
Lead Analyst – NERC Compliance
89 East Avenue
Rochester, New York 14649
Tel. (585) 771-6153
Email: Kristina.Henderson@avangrid.com

Hydro-Quebec TransÉnergie

Primary
Caroline Dupuis, ing.
Acting Director – Reliability Standards and Regulatory Compliance
2 Complexe Desjardins, 19th floor, East Tower
Montréal, Québec, Canada H5B 1H7
Tel. (514) 879-4100 Ext: 5903
Email: dupuis.caroline@hydro.qc.ca

Alternate
Nicolas Turcotte
Acting Manager – Reliability Standards and Regulatory Compliance
2 Complexe Desjardins, 19th floor, East Tower
Montréal, Québec, Canada H5B 1H7
Tel. (514) 798-1223
Ext :8795182
Email: turcotte.nicolas@hydro.qc.ca

Orange & Rockland Utilities, Inc.

Primary
Nick Kowalczyk
Chief System Operator
390 West Route 59
Spring Valley NY 10977
Tel. (845) 577-3796
Email: kowalczykn@oru.com

Alternate
Susmit Patel
Section Manager – Substation & Transmission Engineering
Orange and Rockland Utilities Inc.
390 West Route 59
Spring Valley NY 10977
845-577-3203
Email: patels@oru.com

Eversource Energy

Primary
Quintin Lee
Program Manager - Reliability Compliance
Eversource Energy
780 North Commercial Street
Manchester, NH 03101
Office: (603) 634-3579
Cell: (603) 315-9010
Email: quintin.lee@eversource.com

Alternate
Sharon Flannery
Program Manager – Reliability Compliance
Eversource Energy
107 Selden Street
Berlin, CT
Office: (860) 665-5247
Cell: (860) 402-9157
Email: sharon.flannery@eversource.com

Sector (2) - Reliability Coordinators

New York Independent System Operator

Primary
Gregory A. Campoli
Manager, Reliability Compliance & Industry Affairs
Tel. (518) 356-6159
Email: gcampoli@nyiso.com

Alternate
James (Jim) Grant
Reliability Senior Engineer
Tel. (518) 356-6128
Email: jgrant@nyiso.com

ISO New England, Inc.

Primary
John Pearson
Technical Manager
Tel. (413) 540-4260
Email: jpearson@iso-ne.com

Alternate
Kathleen M. Goodman
Senior Operations Compliance Coordinator
Tel. (413) 535-4111
Email: kgoodman@iso-ne.com

Independent Electricity System Operator

Primary
Helen Lainis
Senior Engineer/Technical Officer
Tel. (905) 855-4106
Email: helen.lainis@ieso.ca

Alternate
Scott Berry
Senior Engineer/Technical Officer
Tel. (905) 403-6912
Email: scott.berry@ieso.ca

Hydro-Quebec TransÉnergie

Primary
Chantal Mazza
Reliability Standards Advisor III
2 Complexe Desjardins, 19th floor, East Tower
Montréal, Québec, Canada H5B 1H7
Tel. (514) 798-1223 Ext. 8795499
Email: mazza.chantal@hydro.qc.ca

Alternate
Michael Godbout
Engineer – Reliability Standards & Operating Procedures Reliability Coordinator
2 Complexe Desjardins, 13th floor, East Tower
Montreal, Québec, Canada H5B 1H7
Tel. (514) 798-1223 Ext. 8795852
Email: Godbout.Michael@hydro.qc.ca

New Brunswick Power Corporation

Primary
Randy MacDonald
Director, Corporate Compliance
Tel. (506) 458-4653
Cell. (506) 470-3536
Email: RaMacDonald@NBPower.com

Alternate
Tim Hicks
Document & Compliance Coordinator
Tel. (506) 458-6511
Cell. (506) 238-3851
Email: Tim.Hicks@nbpower.com

Sector (3) - Transmission Dependent Utilities ("TDUs"); Distribution Companies and Load-Serving Entities ("LSEs")

Consolidated Edison Company of New York, Inc.

Primary
Dermot Smyth
Senior Engineer
Tel. (212) 460-4093
Fax (212) 529-1130
Email: smythd@coned.com

Alternate
Christopher Overberg
Engineer
Tel. (212) 460-2915
Fax (212) 529-1130
Email: overbergc@coned.com

National Grid

Primary
Michael Jones
Manager, Reliability Standards and Policy
40 Sylvan Road
Waltham, Massachusetts 02451
Tel. (781) 907-2404
Email: michael.jones@nationalgrid.com

Alternate

Orange & Rockland Utilities, Inc.

Primary
David Burke
Senior Specialist - Compliance
Tel. (845) 577-2841
Email: burkeda@oru.com

Alternate
Ben Wu
Principal Engineer
Transmission & Substation Engineering
Tel. (845) 577-3713
Email: wub@oru.com

Sector (4) - Generator Owners

Consolidated Edison Company of New York, Inc.

Primary
Peter Yost
Manager, Standards & Compliance
Tel. (212) 460-2889
Fax (212) 529-1130
Email: yostp@coned.com

Alternate
Daniel Valle
Senior Engineer
Tel. (212) 460-4734
Fax (212) 529-1130
Email: valleda@coned.com

New York Power Authority

Primary
Salvatore Spagnolo
Program Manager, Reliability Standards & Compliance
Tel. (914) 390-8224
Mob. (347) 992-7015
Email: Salvatore.Spagnolo@nypa.gov

Alternate
Tom Savin
Program Manager, Reliability Standards & Compliance
Tel. (914) 287-3151
Email: Thomas.Savin@nypa.gov

Dominion Energy Services, Inc.

Primary
Sean Bodkin
NERC Compliance Policy Manager
Dominion Energy Services, Inc.
Tel. (804) 771-8429, tie line 8-786-8429
Cell: (804) 292-5721
Email: Sean.Bodkin@dominionenergy.com

Alternate
Connie Lowe
Regulatory and Market Policy Manager
Dominion Energy Services, Inc.
Tel. (804) 771-4447, tie 8-736-4447
Cell: 804-239-3201
Email: connie.lowe@dominionenergy.com

Ontario Power Generation, Inc.

Primary
Mike Cooke
Director – Reliability Compliance
Tel. (416) 592-6089
Cell: (905) 483-5520
Email: mike.cooke@opg.com

Alternate
David Kwan
Senior Regulatory Analyst
Tel. (416) 592-6369
Email: david.kwan@opg.com

Alternate
Constantin Chitescu
Regulatory Analyst
Tel. (416) 592-6055
Email: constantin.chitescu@opg.com

NextEra Energy, LLC

Primary
Silvia Parada Mitchell
Senior Director, Reliability Standards & Compliance
Tel. (561) 904-3767
Email: silvia.parada.mitchell@fpl.com

Alternate
Summer Esquerre
Director Reliability Standards & Compliance
Tel. (561) 904-3765
Email: summer.esquerre@fpl.com

Alternate
Rogelio Moraitis
Senior Compliance Analyst
Reliability Standards and Compliance
Tel. (561) 904-3402
Email: Rogelio.Moraitis@nee.com

Entergy Services, Inc

Primary
Glen Smith
NERC Compliance
Entergy Services, Inc
440 Hamilton Avenue
White Plains, NY 10601
914-272-3513
Email: gsmith@entergy.com

Alternate
Mark Thomas
Manager
NERC Compliance, Standards & Implementation
Tel: (501)228-2885
Email: mthoma3@entergy.com

PSEG

Primary
Sean Cavote
NERC Compliance and Advocacy
PSEG Law Department
80 Park Plaza, P3
Newark, NJ 07102-4194
973-430-5310
Email: sean.cavote@pseg.com

Alternate
Tim Kucey
Manager NERC/CIP Compliance - Fossil
40 Cragwood Road
South Plainfield, NJ 07080
908-412-3078
Email: Timothy.Kucey@PSEG.com

Sector (5) - Marketers, Brokers and Aggregators

Consolidated Edison Company of New York, Inc.

Primary
Ashmeet Kaur
Engineer
Tel. (212) 460-4155
Fax (212) 529-1130
Email: kaura@coned.com

Alternate
Qinling Zheng
Engineer
Tel. (212) 460-2790
Fax (212) 529-1130
Email: zhengq@ConEd.com

Utility Services, Inc.

Primary
Brian Robinson
COO
Tel. (802) 241-1400
Email: brian.robinson@utilitysvcs.com

Alternate
Brian Evans-Mongeon
President/CEO
Tel. (802) 241-1400
Email: brian.evans-mongeon@utilitysvcs.com

Sector (6) – State and Provincial Regulatory and/or Governmental Authorities

New York Power Authority

Primary
Shivaz Chopra
Director, Reliability Standards & Compliance
Tel. (914) 681-6828
Tel. (914) 391-6839
Email: shivaz.chopra@nypa.gov

Alternate
Erick Barrios
Engineer, Reliability Standards & Compliance
Tel. (914) 681-6781
Tel. (914) 506-2152
Email: Erick.Barrios@nypa.gov

New York State Department of Public Service

Primary	Alternate
Vijay Puran	Jerry Ancona
Utility Supervisor, Bulk Electric Systems	Senior Engineer
Tel. (518) 486-5948	Tel. (315) 448-7300
Email: vijay.puran@dps.ny.gov	Email: Jerry.Ancona@dps.ny.gov

Sector 7 – Sub-Regional Reliability Councils, Customers and Other Regional Entities and Interested Entities

New York State Reliability Council, LLC

Primary	Alternate
Alan Adamson	
Independent Consultant	
2104 Braxton Street	
Clermont, FL 34711	
Tel. (352) 989-4653	
Email: aadamson@nycap.rr.com	

Independent

Primary	Alternate
David Kiguel	
Independent Consultant	
Toronto, Canada	
Email: David.kiguel@outlook.com	

AESI, Inc.

Primary	Alternate
Joel Charlebois	
Vice President, Regulatory Compliance	
Tel. (770) 870-1630 x 236	
Cell: (718) 419-4012	
Email: JoelC@aesi-inc.com	

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 second quarter of 2019, in accordance with the January 16 Order. This variance

---

[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.*

information was posted on NERC's website August 7, 2019 and was reviewed at the August 14, 2019 open meeting of the NERC Finance and Audit Committee. The unaudited report was approved by the NERC Finance and Audit Committee at its meeting on August 14, 2019, and is being recommended for approval by the NERC Board of Trustees at its meeting on August 15, 2019.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

Meredith M. Jolivert
Senior Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
Meredith.jolivert@nerc.net

Andy Sharp
Interim Chief Financial Officer and Controller
North American Electric Reliability Corporation
3353 Peachtree Road NE, Suite 600 – North Tower
Atlanta, GA 30326
(404) 446-9732
Andy.Sharp@nerc.net

III. DISCUSSION OF SIGNIFICANT VARIANCES BETWEEN 2019 BUDGET AND ACTUAL PROJECTED 2019 RESULTS

The attached second quarter 2019 variance report compares actual (unaudited) financial results to NERC's budgeted expenditures as of June 30, 2019, and projected year–end 2019 financial results to NERC's total 2019 budgeted expenditures. NERC is providing additional discussion of significant variances between the projected (unaudited) year-end 2019 results and NERC's 2019 budgeted expenditures, by NERC department or program area and by major activity within departments and program areas. This discussion focuses on variances of $500,000 or more between projected year-end 2019 results and the 2019 budget. NERC has focused on projected year-end variances in excess of budget of $500,000 or more, because Section 7(b)(ii)

of the Settlement Agreement specifies that NERC will file for Commission review and approval proposals approved by the NERC Board of Trustees to expend $500,000 or more from Operating Reserves designated for "unforeseen contingencies" (as defined in NERC's Working Capital and Operating Reserves Policy), *i.e.*, where any amount allocated from the unforeseen contingencies account of Operating Reserves plus any amount redirected from previously budgeted funds is, in the aggregate, $500,000 or more for any one specific project or major activity in a program area.

A. Projected Variances of $500,000 or more by Department or Program Area

In late 2018, NERC management went through an organizational assessment, including the alignment of various programs and staffing resources according to roles and responsibilities, and re-characterized several employees across multiple departments. In general, these employees maintained the same responsibilities and functional oversight, but were assigned different managers or departments. In some cases, similar roles were consolidated to align certain technical functions. The changes had no effect on total FTEs for the company, and the net cost impact of these movements was immaterial. However, for financial presentation purposes as it relates to the original 2019 Business Plan & Budget, these four departments now reflect budget variances because of the change in alignment of staffing within and across these program areas: Compliance Assurance; Compliance Analysis, Registration and Certification; Reliability Assessment and System Analysis; and Performance Analysis. As of June 30, 2019, Compliance Assurance is projected to be over budget by $1,200,041, Compliance Analysis, Registration and Certification is projected to be under budget by $1,025,397, Reliability Assessment and System Analysis is projected to be under budget by $959,361, and Performance Analysis is projected to be over budget by $537,654 (primarily due to the staffing reorganization discussed previously and unbudgeted costs associated with the Florida Reliability Coordinating Council (FRCC)

Regional Entity dissolution costs). Other departments and program areas reflect over and under budget amounts as well resulting from this reorganization, but none were greater than $500,000. Legal and Regulatory is projected to be over budget by $917,339 due to personnel transition costs and search fees, as well as Internal Audit contracts and consultants expenditures that were budgeted in the Finance and Accounting department that will be charged to the Legal and Regulatory department.

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

Meredith M. Jolivert
Senior Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
meredith.jolivert@nerc.net

Counsel for North American Electric Reliability Corporation

Dated: August 14, 2019

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 14th day of August, 2019.

/s/ Meredith M. Jolivert

Meredith M. Jolivert
Counsel for North American Electric Reliability Corporation

ATTACHMENT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Summary of Unaudited Results For the Month Ending June 30, 2019

Table of Contents

		Page
1.	Executive Summary	
	a. Projected Year-End Results	2
	b. Year-to-Date Actual Results	3
2.	Detailed Operating Results	
	a. Variances by Revenue and Expense Category	4
	b. Variances by Department	6
3.	Supplemental Schedules	
	a. Schedule 1 – Year-End Projected Reserves	7
	b. Schedule 2 – IT Projects	8
	c. Schedule 3 – E-ISAC & CRISP Summary of Activity	11

Executive Summary

Projected Year-End Results
($ millions)

FUNDING	Projected	Budget	Over (Under)
Revenues	$ 78.8	$ 78.5	$ 0.3
Funding from Reserves			
Assessment Stabilization Reserve	$ 0.6	$ 0.6	-
TOTAL FUNDING	**$ 79.4**	**$ 79.1**	**$ 0.3**
EXPENDITURES			
Expenses (excluding Depreciation)	$ 76.9	$ 75.2	$ 1.7
Fixed Asset Additions	3.8	4.8	(1.0)
TOTAL EXPENDITURES	**$ 80.7**	**$ 80.0**	**$ 0.7**
RESERVE INCREASE (DECREASE)	**$ (1.3)**	**$ (0.9)**	**$ (0.4)**

Funding

- Revenues
  - Expected to be slightly over budget at year-end primarily due to higher than budgeted investment income, and will be partially offset by lower third-party revenues for the CRISP program.

Expenditures

- Expenses (excluding depreciation)
  - Personnel expenses are expected to be over budget mainly because of transition costs and search fees.
  - Contracts and consultants expenses are projected to be over budget primarily due to FRCC transition work, SOCCED database system upgrades, and E-ISAC support costs (which are offset by lower spending in other E-ISAC categories).
- Fixed Asset Additions
  - Projected to be below budget in order to offset other increased costs.

Operating Reserve Increase (Decrease)

- Projected reserve decrease from operating activity is $1.3M versus a budgeted decrease of $0.9M.

Year-to-Date Actual Results
($ millions)

FUNDING	Actual	Budget	Over (Under)
Revenues	$ 39.5	$ 39.3	$ 0.2
Funding from Reserves			
Assessment Stabilization Reserve	0.6	0.6	-
TOTAL FUNDING	**$ 40.1**	**$ 39.9**	**$ 0.2**
EXPENDITURES			
Expenses (excluding Depreciation)	$ 36.9	$ 38.4	$ (1.5)
Fixed Asset Additions	1.7	2.4	(0.7)
TOTAL EXPENDITURES	**$ 38.6**	**$ 40.8**	**$ (2.2)**
RESERVE INCREASE (DECREASE)	**$ 1.5**	**$ (0.9)**	**$ 2.4**

Funding

- Revenues
  - Slightly over budget mainly due to higher investment income.

Expenditures

- Expenses (excluding depreciation)
  - Contracts and Consultants expenses are under budget primarily because of the expected timing of expenditures versus budget.
- Fixed Asset Additions
  - Under budget largely due to the expected timing of expenditures versus budget and lower spending to offset increased costs in other areas.

Operating Reserve Increase (Decrease)

- Reserve increase from operating activity is higher than budget by $2.4 million mainly because of the expected timing of expenditures versus budget.

Detailed Operating Results

Variances by Revenue and Expense Category

Total NERC (including CRISP)

	YTD Actual	YTD Budget	YTD Over (Under)	% Over (Under)	Annual Projection	Annual Budget	Annual Over (Under)	% Over (Under)
TOTAL FUNDING	**$ 40,099,143**	**$ 39,872,674**	**$ 226,468**	**0.6%**	**$ 79,387,028**	**$ 79,130,349**	**$ 256,679**	**0.3%**
EXPENDITURES								
Personnel	$ 22,578,141	$ 22,627,743	$ (49,602)	(0.2%)	$ 44,389,285	$ 43,952,190	$ 437,095	1.0%
Meetings, Travel, and Conference Calls	2,034,956	1,771,450	263,506	14.9%	3,747,062	3,380,400	366,662	10.8%
Contracts and Consultants	5,788,775	7,597,584	(1,808,809)	(23.8%)	15,579,153	15,043,318	535,835	3.6%
Rent and Facilities	1,647,411	1,637,529	9,882	0.6%	3,305,058	3,335,058	(30,000)	(0.9%)
Office Costs, Professional, and Misc.*	4,756,352	4,641,523	114,830	2.5%	9,696,877	9,346,517	350,360	3.7%
Other Non-Operating Expenses	63,270	113,018	(49,748)	(44.0%)	139,971	214,171	(74,200)	(34.6%)
Fixed Asset Additions*	1,738,837	2,389,000	(650,163)	(27.2%)	3,847,990	4,778,000	(930,010)	(19.5%)
TOTAL EXPENDITURES	**$ 38,607,741**	**$ 40,777,847**	**$ (2,170,106)**	**(5.3%)**	**$ 80,705,396**	**$ 80,049,655**	**$ 655,742**	**0.8%**
RESERVE INCREASE (DECREASE)	**$ 1,491,401**	**$ (905,172)**	**$ 2,396,574**	**(264.8%)**	**$ (1,318,368)**	**$ (919,306)**	**$ (399,063)**	**43.4%**
FTEs	**201.8**	**205.9**	**(4.1)**	**(2.0%)**	**202.0**	**204.9**	**(2.9)**	**(1.4%)**

***** Excludes depreciation expense

Following is a brief summary of variances by category:

- Personnel Expense
  - Expected to be over budget primarily due to transition costs and search fees.
- Meeting, Travel, and Conference Call Expense
  - Currently and projected to be over budget due to higher attendance at workshops and conferences, which is partially offset by increased revenues for these events.
- Contracts and Consultants Expense
  - Under budget due to lower costs from the CRISP program contractor and expected timing of expenditures versus budget. Expected to be over budget at year-end because of unbudgeted costs for SPP RE transition work, SOCCED database system upgrades, and E-ISAC support costs. Also, amounts for Internal Audit projects that were originally budgeted in the Finance and Accounting department will be charged to the Legal and Regulatory department, which nets to an $86k over budget amount between those departments.

CONTRACTS and CONSULTANTS	YTD Actual	YTD Budget	YTD Over (Under)	Annual Projection	Annual Budget	Annual Over (Under)
Reliability Standards	$ -	$ 25,000	$ (25,000)	$ 50,000	$ 50,000	$ (0)
Compliance Assurance	-	25,000	(25,000)	50,000	50,000	(0)
Compliance Analysis, Registration and Certification	-	-	-	-	-	-
Compliance Enforcement	35,131	80,500	(45,369)	161,000	161,000	(0)
Reliability Assessment and System Analysis	124,050	312,500	(188,450)	485,000	625,000	(140,000)
Situation Awareness	926,693	878,920	47,773	1,329,740	1,280,990	48,750
Event Analysis	-	-	-	-	-	-
Performance Analysis	236,446	326,783	(90,336)	775,243	653,565	121,678
E-ISAC	558,245	910,250	(352,005)	2,259,475	1,820,500	438,975
Training, Education, and Personnel Certification	301,518	248,500	53,018	632,000	497,000	135,000
General and Administrative and Executive	94,304	80,000	14,304	220,000	220,000	-
Legal and Regulatory	-	-	-	385,900	-	385,900
Policy and External Affairs	13,260	10,000	3,260	24,000	20,000	4,000
Information Technology	725,995	1,021,382	(295,386)	1,969,295	2,042,763	(73,468)
Human Resources and Administration	277,875	212,500	65,375	605,000	690,000	(85,000)
Finance and Accounting	60,077	237,500	(177,423)	175,000	475,000	(300,000)
TOTAL (excluding CRISP)	**$ 3,353,595**	**$ 4,368,834**	**$ (1,015,239)**	**$ 9,121,653**	**$ 8,585,818**	**$ 535,835**
CRISP	2,435,180	3,228,750	(793,570)	6,457,500	6,457,500	-
TOTAL (including CRISP)	**$ 5,788,775**	**$ 7,597,584**	**$ (1,808,809)**	**$ 15,579,153**	**$ 15,043,318**	**$ 535,835**

- Office Costs
  - Projected to be over budget at year-end primarily due to software costs that were budgeted in fixed assets but that will be charged to office costs due to the type of license acquired.
- Fixed Asset Additions
  - Under budget year-to-date largely because of the expected timing of expenditures versus budget, and projected to be under budget mainly due to lower spending to offset increased costs in other areas.

Variances by Department

DIRECT EXPENSES and NET FIXED ASSETS	YTD Actual	YTD Budget	YTD Over (Under)	Annual Projection	Annual Budget	Annual Over (Under)
Reliability Standards	$ 1,718,880	$ 1,747,839	$ (28,959)	$ 3,839,827	$ 3,419,581	$ 420,245
Compliance Assurance	3,272,783	2,623,916	648,866	6,378,546	5,178,505	1,200,041
Compliance Analysis, Registration and Certification	1,212,596	1,470,032	(257,437)	1,856,407	2,881,804	(1,025,397)
Compliance Enforcement	1,851,487	1,963,488	(112,001)	3,672,568	3,861,690	(189,122)
Reliability Assessment and System Analysis	1,789,349	2,358,580	(569,231)	3,646,746	4,606,107	(959,361)
Situation Awareness	1,638,846	1,754,698	(115,853)	3,028,102	3,012,404	15,698
Event Analysis	1,427,052	1,441,638	(14,586)	2,583,676	2,771,658	(187,982)
Performance Analysis	1,609,272	1,462,330	146,941	3,411,621	2,873,967	537,654
E-ISAC	4,486,432	5,386,945	(900,513)	10,733,378	10,649,090	84,288
Training, Education, and Personnel Certification	774,899	678,556	96,343	1,599,892	1,367,755	232,137
General and Administrative and Executive	4,229,069	4,120,074	108,996	8,101,933	8,144,200	(42,267)
Legal and Regulatory	1,969,760	1,989,315	(19,555)	4,796,130	3,878,791	917,339
Policy and External Affairs	1,210,817	1,285,423	(74,606)	2,534,800	2,510,721	24,079
Information Technology	5,675,631	5,908,315	(232,684)	11,681,408	11,696,532	(15,125)
Human Resources	1,191,708	1,163,893	27,815	2,268,316	2,562,371	(294,056)
Finance and Accounting	1,601,280	1,277,795	323,485	2,698,138	2,553,747	144,390
TOTAL (excluding CRISP)	**$ 35,659,860**	**$ 36,632,838**	**$ (972,978)**	**$ 72,831,487**	**$ 71,968,925**	**$ 862,562**
CRISP	2,947,881	4,145,009	(1,197,127)	7,873,909	8,080,729	(206,820)
TOTAL EXPENSES and NET FIXED ASSETS	**$ 38,607,741**	**$ 40,777,847**	**$ (2,170,106)**	**$ 80,705,396**	**$ 80,049,655**	**$ 655,741**

In late 2018, NERC management went through an organizational assessment involving various program areas and re-characterized several employees across multiple departments. In most cases, these employees kept the same responsibilities and functional oversight, but were assigned new departments and/or consolidated with other similar roles to align certain technical functions. The changes had no effect on the total FTEs, and the net cost impact of these movements was immaterial. The following program areas were impacted by this review:

- Reliability Standards
- Compliance Assurance
- Compliance Analysis, Registration and Certification
- Reliability Assessment and System Analysis
- Event Analysis
- Performance Analysis

Following is a brief summary of variances by department:

- E-ISAC - Under budget year-to-date largely because of the expected timing of expenditures and hiring of FTEs versus the budget.
- Legal and Regulatory - Projected to be over budget at year-end primarily due to transition costs and search fees, as well as Internal Audit expenditures that were budgeted in the Finance and Accounting department that will be charged to the Legal and Regulatory department.
- CRISP - Under budget year-to-date largely because of the expected timing of expenditures versus the budget from the program contractor.

Supplemental Schedules

Schedule 1 – Year-End Projected Reserves

Reserve Account	Beginning Balance [1]	Budgeted Funding	Budgeted Uses	Other Funding (Uses) [2]	Net Financing Activity [3]	Ending Balance
Operating Contingency	**$ 5,644,359**	$ 550,000	$ (1,067,980)	$ (678,640)	$ 694,646	**$ 5,142,385**
Future Obligations	**2,535,333**	-	(480,457)	64,843	-	**2,119,719**
Assessment Stabilization	**2,071,000**	-	(550,000)	-	-	**1,521,000**
System Operator	**592,110**	148,674	-	(270,423)	-	**470,361**
CRISP	**500,000**	-	-	-	-	**500,000**
Total Reserves	**$ 11,342,801**	$ 698,674	$ (2,098,437)	$ (884,219)	$ 694,646	**$ 9,753,464**

NOTES:

(1) Some 2019 beginning balances have been adjusted from the 12/31/2018 variance report balances as the result of a reconciliation to the final audited balance sheet.

(2) The column Other Funding (Uses) primarily reflects the net impact of normal operations. For example, under normal circumstances, if NERC was tracking well under budget in actual expenditures, this would reflect additional funds into the reserve account. It also reflects the increase or decrease in working capital during the period.

(3) Net financing activity in 2019 reflects principal debt repayments for borrowings originating in 2016. NERC did not make budgeted borrowings for 2017 and 2018 in light of a favorable working capital position, and is projected to borrow 50% of its 2019 budgeted financing in 2019.

Schedule 2 – IT Projects

Projects in Progress	Project Budget [1]	Actual Spend	Expected Spend	Expected Over (Under) Budget
CMEP Technology Project (2017-2020)	$ 5,403,000	$ 2,760,107	$ 5,403,000	$ -
Entity Registration - CORES (2018-2020)	1,400,000	1,221,418	1,373,797	(26,203)
SAFNR V3	221,500	-	188,000	(33,500)
Document Management - Records Center Reconfiguration	190,500	92,700	190,500	-
Multifactor Authentication	27,660	7,173	27,660	-
FRCC Dissolution	128,497	121,713	152,303	23,806
Standards	300,000	61,863	300,000	-
E-ISAC - Customer Relationship Managmenet (CRM)	237,800	133,770	293,300	55,500
Footprints Upgrade	84,753	-	84,753	-

NOTES:

(1) The Project Budget noted above usually corresponds to the approved business case for each project and funds for each project are drawn from the available budget. In some projects, business cases may not be prepared, particularly when a project is smaller and/or may be in response to a FERC order.

** Some of these projects span multiple years, so the amounts above do not represent a single budget year expenditure.*

** The amounts noted above do not include internal labor or license/maintenance/support costs and reflect only external (consultant) costs of the projects.*

Schedule 2 (continued) – IT Projects

CMEP Technology Project
(Started May 2017 / Planned Completion Dec 2020)
This project will provide registered entities, Regional Entities, and NERC the ability manage the compliance and enforcement processes and data in a single ERO Enterprise system. Today, those processes and related data are managed across three separate systems that have to be synchronized (webCDMS, CITS, and CRATS).

Entity Registration - CORES
(Started Dec 2017 / Planned Completion Dec 2019)
NERC is undertaking an effort to both standardize and modernize the Entity Registration process. The discovery phase of the Centralized Organization Registration Entity System (CORES) project includes the capture of Region-specific needs, variations, and exceptions in the registration process. CORES will be a centralized entity registration process, which will require the retirement of registration in CDMS, CITS, and CRATS. The Joint Registration Organization (JRO) portion of the project will be combined with the CORES production release in 2019.

SAFNR V3
(Started May 2019 / Planned Completion Nov 2019)
One of the primary functions of the ERO Enterprise is to maintain situational awareness of Bulk Power System conditions and provide accurate and timely information regarding threats that may adversely impact reliability. This project will replace the existing Situation Awareness for FERC, NERC, and the Regional Entities system (SAFNR V2) system with a new version to reduce reliability risk, provide new capabilities, reduce corporate risk, and increase productivity.

Document Management – Records Center Reconfiguration
(Started May 2019 / Planned Completion Dec 2019)
The Record Center is in alignment with the original intent and business case for Document Management. One of the key items for addressing information management across all program areas, was to have the ability to address document retention. The Record Center will be configured in accordance with the NERC Records Retention and Destruction policy, allowing records to be managed and retained in accordance with policy.

Multifactor Authentication
(Started Jan 2019 / Planned Completion Jul 2019)
The purpose of this project is to implement the DUO Multi Factor Authorization solution to enhance the overall security of the NERC ERO suite of applications and to meet existing requirements for applications currently under development, primarily CORES and CMEP/Align projects. Multi-factor authorization provides functionality requiring multiple means of user authentication (Mobile PIN code, etc.) in addition to traditional user authentication methods like user name and password.

Schedule 2 (continued) – IT Projects

FRCC Dissolution
(Started Jan 2019 / Planned Completion Jun 2019)
With FRCC dissolving, NERC assessed the changes required to applications that contained FRCC data and the reassignment/classification of such information. The inventory requires the mapping utility, functionality, migration, and support efforts by both Region and entity. Activities include facilitated discussions with IT and business owners of impacted applications to capture and document high-level, as well as more detailed, requirements necessary to support the transition of registered entities from FRCC to SERC.

Standards
(Started Jan 2019 / Planned Completion Oct 2019)
In support of the CMEP Technology Project, this project involves the movement all of the Standards data from the old source system to the new one.

E-ISAC – Customer Relationship Management (CRM)
(Started Jul 2019 / Planned Completion Oct 2019)
The purpose of this project is to select and implement a Customer Relationship Management (CRM) tool to assist the E-ISAC team in growing its North American electricity owner/operator base from the current roughly 1,000 members to a progressively greater share of the roughly 5,000 total. The team will be able to do so through improved outreach, marketing, and overall engagement and tracking processes expected from use of the new tool. The plan is also to integrate with the E-ISAC Portal.

Footprints Upgrade
(Started Mar 2019 / Planned Completion Aug 2019)
The purpose of this project is to replace the current Footprints helpdesk application used to support both NERC and the ERO applications with the latest version.

Schedule 3 – E-ISAC and CRISP Summary of Activity

TOTAL E-ISAC (including CRISP)

FUNDING	YTD Actual	Annual Projection	Annual Budget	Projected Over (Under)
Assessments	$ 9,813,949	$ 19,627,897	$ 19,627,897	$ -
Other Funding	4,008,492	7,746,805	7,767,730	(20,925)
TOTAL FUNDING	$ 13,822,440	$ 27,374,702	$ 27,395,627	$ (20,925)
EXPENDITURES				
Personnel Expense	$ 3,692,983	$ 7,664,050	$ 8,180,123	$ (516,073)
Meeting Expense	241,331	662,142	418,000	244,142
Operating Expenses (excluding Depreciation)	3,465,223	9,961,095	9,431,696	529,399
Fixed Assets (excluding Depreciation and Fixed Asset Allocation)	34,776	320,000	700,000	(380,000)
Total Direct Costs (excluding Depreciation and Allocations)	$ 7,434,313	$ 18,607,287	$ 18,729,819	$ (122,532)
Indirect Expense Allocation	4,162,502	8,482,370	9,004,572	(522,202)
Fixed Asset Allocation	(200,822)	(320,265)	(338,764)	18,499
TOTAL EXPENDITURES (excluding Depreciation, including Allocations)	$ 11,395,992	$ 26,769,391	$ 27,395,627	$ (626,235)
RESERVE INCREASE (DECREASE)	$ 2,426,448	$ 605,311	$ -	$ 605,311

Schedule 3 (continued) – E-ISAC and CRISP Summary of Activity

CRISP

FUNDING	YTD Actual	Annual Projection	Annual Budget	Projected Over (Under)
Assessments	$ 763,194	$ 1,526,388	$ 1,526,388	$ -
Other Funding	3,815,750	7,437,873	7,517,319	(79,446)
TOTAL FUNDING	$ 4,578,944	$ 8,964,261	$ 9,043,707	$ (79,446)
EXPENDITURES				
Personnel Expense	$ 351,179	$ 707,711	$ 965,793	$ (258,082)
Meeting Expense	32,445	49,262	48,000	1,262
Operating Expenses (excluding Depreciation)	2,564,257	6,966,936	6,966,936	-
Fixed Assets (excluding Depreciation and Fixed Asset Allocation)	-	150,000	100,000	50,000
Total Direct Costs (excluding Depreciation and Allocations)	$ 2,947,881	$ 7,873,909	$ 8,080,729	$ (206,820)
Indirect Expense Allocation	414,338	979,904	1,000,605	(20,702)
Fixed Asset Allocation	(19,990)	(36,998)	(37,628)	630
TOTAL EXPENDITURES (excluding Depreciation, including Allocations)	$ 3,342,229	$ 8,816,815	$ 9,043,707	$ (226,892)
RESERVE INCREASE (DECREASE)	$ 1,236,715	$ 147,446	$ -	$ 147,446

E-ISAC (excluding CRISP)

FUNDING	YTD Actual	Annual Projection	Annual Budget	Projected Over (Under)
Assessments	$ 9,050,755	$ 18,101,509	$ 18,101,509	$ -
Other Funding	192,742	308,932	250,411	58,521
TOTAL FUNDING	$ 9,243,496	$ 18,410,441	$ 18,351,920	$ 58,521
EXPENDITURES				
Personnel Expense	$ 3,341,804	$ 6,956,339	$ 7,214,330	$ (257,991)
Meeting Expense	208,886	612,880	370,000	242,880
Operating Expenses (excluding Depreciation)	900,967	2,994,159	2,464,760	529,399
Fixed Assets (excluding Depreciation and Fixed Asset Allocation)	34,776	170,000	600,000	(430,000)
Total Direct Costs (excluding Depreciation and Allocations)	$ 4,486,432	$ 10,733,378	$ 10,649,090	$ 84,288
Indirect Expense Allocation	3,748,164	7,502,466	8,003,966	(501,500)
Fixed Asset Allocation	(180,832)	(283,268)	(301,136)	17,869
TOTAL EXPENDITURES (excluding Depreciation, including Allocations)	$ 8,053,763	$ 17,952,577	$ 18,351,920	$ (399,343)
RESERVE INCREASE (DECREASE)	$ 1,189,733	$ 457,864	$ -	$ 457,864

ERO Enterprise (NERC and Regional Entities) Combined Summary of Unaudited Results

June 30, 2019

The ERO Enterprise was under budget $3.1M (3.1%) for combined expense and fixed asset (capital) spending. The budget variances ranged from 13.0% under budget to 41.6% over budget. The year-end projection for the ERO Enterprise is to be over budget by 1.0%.

Total Budget (Total Expenses plus the Increase (Decrease) in Fixed Assets)

Entity	2019 YTD Actual	2019 YTD Budget	Over (Under) $	Over (Under) %	2019 Year-End Projected	2019 Year-End Budgeted	Over (Under) $	Over (Under) %
NERC	$ 38,607,741	$ 40,777,847	$ (2,170,106)	(5.3%)	$ 80,705,396	$ 80,049,655	$ 655,741	0.8%
FRCC	4,816,108	3,401,414	1,414,694	41.6%	5,139,340	6,695,786	(1,556,446)	(23.2%)
MRO	6,853,745	7,875,517	(1,021,772)	(13.0%)	14,773,126	15,980,356	(1,207,230)	(7.6%)
NPCC	7,303,311	7,655,063	(351,752)	(4.6%)	15,615,914	15,803,889	(187,975)	(1.2%)
RF	11,269,660	11,744,579	(474,919)	(4.0%)	22,321,620	22,648,458	(326,838)	(1.4%)
SERC	9,216,005	8,798,216	417,789	4.7%	23,276,025	18,144,948	5,131,077	28.3%
Texas RE	5,988,406	6,512,106	(523,700)	(8.0%)	13,002,845	13,069,595	(66,750)	(0.5%)
WECC	12,805,455	13,233,246	(427,791)	(3.2%)	26,480,478	26,950,566	(470,088)	(1.7%)
	$ 96,860,431	**$ 99,997,988**	**$ (3,137,557)**	**(3.1%)**	**$ 201,314,744**	**$ 199,343,253**	**$ 1,971,491**	**1.0%**

- NERC was under budget $2.2M (5.3%) primarily due to timing of expenditures for contracts and consultants and fixed assets. The company expects to be slightly over budget at year-end.
- FRCC was over budget $1.4M (46.1%) and projects to be under budget $1.6M (23.2%) at year-end due to changing operations associated with the dissolution of FRCC Regional Entity (RE) functions. FRCC transferred its RE activities to SERC effective July 1, 2019, and will complete the wind down of its RE business on August 31, 2019. A FERC-approved special assessment of $630k has been charged to Load-Serving Entities in the FRCC RE footprint to assist in funding the wind down costs of the RE.
- MRO was under budget $1.0M (13.0%), which is attributable primarily to lower spending in personnel and travel costs, and timing of contracts and consultants expenses. The company expects to be under budget $1.2M (7.6%) at year-end primarily due to under budget personnel costs as MRO continues to become fully staffed.
- NPCC was under budget $352k (4.6%) mainly as a result of lower personnel costs and timing of meeting and contractor expenses. The company expects to be under budget $188k (1.2%) at year-end.
- RF was under budget $475k (4.0%), largely due to lower personnel costs and timing of contracts and consultants, computer, and leasehold improvement expenses. The company expects to be under budget $327k (1.4%) at year-end.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Summary of Unaudited Results Second Quarter 2019

Andy Sharp, Interim CFO and Controller
Finance and Audit Committee Meeting
August 14, 2019

RELIABILITY | RESILIENCE | SECURITY

2019 Second Quarter YTD Results

- Total funding – $200k (0.6%) over budget
  - Higher investment income
- Total expenditures – $2.2M (5.3%) under budget
  - Primarily due to the expected timing of expenditures versus budget
- Net impact was $2.4M increase in reserves

2019 Year-End Projections

- Funding – $300k (0.3%) over budget
  - Higher investment income and offset by lower third-party revenues needed to fund CRISP
- Operating expenditures – $700k (0.8%) over budget
  - Personnel expenses expected to be over budget due to transition costs and search fees
  - Contracts and consultants projected to be over budget due to FRCC transition work, SOCCED system enhancements, and E-ISAC support costs
  - Meeting expenses expected to be higher than budget, but partially offset by workshop fee funding
  - Fixed assets projected to be under budget

2019 Year-End Projections

- Projected net results from operating activities – $400k unfavorable to budget
- Debt service will be $700k favorable to budget
- 2019 loan borrowing for ERO software projects expected to be lower than budget, due to favorable debt service

2019 Projected Year-End Reserves

- Total projected reserve balances – $9.8M
  - Operating Contingency Reserve – $5.1M
  - Assessment Stabilization Reserve – $1.5M
  - Future Obligation Reserve – $2.1M
  - System Operator Reserve – $470k
  - CRISP Reserve – $500k
- Total year-end reserves projected in 2019 budget – $8.6M

Questions and Answers

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RM19-10-000**

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") regarding proposed Reliability Standard TPL-001-5 – Transmission System Planning Performance Requirements issued by the Federal Energy Regulatory Commission ("FERC" or "Commission") in this proceeding on June 20, 2019.[1] NERC provides these comments as the Commission-certified electric reliability organization ("ERO") responsible for the development and enforcement of mandatory Reliability Standards, including proposed Reliability Standard TPL-001-5.[2]

In the NOPR, the Commission proposes to approve Reliability Standard TPL-001-5 and the associated implementation plan, Violation Risk Factors, and Violation Severity Levels submitted by NERC for approval. The Commission also proposes to direct that NERC develop modifications to the standard to require planning entities to develop Corrective Action Plans for Protection System single points of failure with three-phase faults if their studies indicate potential Cascading. The Commission has requested comments on its proposals.

---

[1] Notice of Proposed Rulemaking, *Transmission Planning Reliability Standard TPL-001-5*, 167 FERC ¶ 61,249 (2019) ("NOPR").

[2] The Commission certified NERC as the ERO in 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006), *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030 (2007), *order on clarification and reh'g*, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

NERC supports the Commission's proposal to approve proposed Reliability Standard TPL-001-5 and its associated elements. For the reasons discussed in these comments, NERC does not support the Commission's proposal to direct further modifications to the standard at this time. NERC respectfully requests that the Commission approve the proposed standard as filed by NERC.

I. BACKGROUND

On December 7, 2018, NERC submitted a petition for approval of proposed Reliability Standard TPL-001-5 – Transmission System Planning Performance Requirements.[3] As explained in NERC's Petition, proposed Reliability Standard TPL-001-5 reflects two sets of revisions intended to enhance the quality and rigor of Planning Assessments, thereby contributing to a more reliable Bulk Power System ("BPS").

The first set of revisions is intended to address two Commission directives from Order No. 786 approving Reliability Standard TPL-001-4.[4] These directives relate to: (i) the study of known outages of less than six months duration; and (ii) the study, as part of Stability analysis, of the possible unavailability of long lead-time equipment, consistent with the entity's spare equipment strategy.[5]

The second set of revisions is intended to enhance requirements for the study of Protection System single points of failure.[6] NERC identified Protection System single points of failure as a reliability risk to be addressed based on an analysis of data collected pursuant to NERC's authority

---

[3] *Petition of NERC for Approval of Proposed Reliability Standard TPL-001-5*, Docket No. RM19-10-000 (Dec. 7, 2018) (the "Petition").

[4] *Transmission Planning Reliability Standards*, Order No. 786, 145 FERC ¶ 61,051 (2013) ("Order No. 786").

[5] *Id.* at PP 40, 89.

[6] In this context a Protection System "single point of failure" refers to a non-redundant component of a Protection System that, if it failed, would affect Normal Clearing of Faults.

under Section 1600 of the NERC Rules of Procedure.[7] To address the identified reliability risk, the proposed standard contains revisions to two existing TPL-001 planning scenarios and the associated footnote 13. These revised planning scenarios are: (i) the Table 1, Category P5 planning event, which would require the planning entity to study the impacts of Delayed Fault Clearing due to a Protection System single point of failure with a single line-to-ground fault; and (ii) Table 1, Stability extreme events 2.a-h,[8] which would require the planning entity to study the impacts of a three-phase fault with a Protection System single point of failure resulting in Delayed Fault Clearing. The revised footnote 13 includes a more comprehensive list of potentially problematic Protection System components to be studied for both the planning and extreme events.

On June 20, 2019, the Commission issued the NOPR proposing to approve Reliability Standard TPL-001-5. In the NOPR, the Commission proposes to approve TPL-001-5 as just, reasonable, not unduly discriminatory or preferential, and in the public interest.[9] Further, the Commission states that proposed Reliability Standard TPL-001-5 satisfies the Commission's Order No. 786 directives.[10] The Commission, however, expressed concern that the proposed standard may leave a reliability gap because it would not require entities to develop Corrective Action Plans for the revised Table 1, Stability 2.e-h (three-phase fault) extreme event scenario if

---

7 *See* Petition at 9-10, citing NERC System Protection and Control Subcommittee and System Analysis and Modeling Subcommittee, *Order No. 754: Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* (Sep. 2015) ("SPCS/SAMS Report"), https://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/FERC%20Order%20754%20Final%20Report%20-%20SPCS-SAMS.pdf.

8 As explained in NERC's Petition, Items 2.a through 2.d are revised to strike the term "relay failure" and the associated footnote 13. The study of a "non-redundant component of a Protection System" (and the associated footnote 13) now appear separately in Items 2.e through 2.h. Petition at 22-23.

9 NOPR at P 15.

10 *Id.* at P 16.

their studies indicate potential Cascading.[11] As proposed, the standard would require planning entities to conduct "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequence of the event(s)" when potential Cascading is identified, consistent with the requirement for all other TPL-001 extreme events.[12]

Based on its concern, the Commission proposes to direct "that NERC develop modifications to the Reliability Standards to require corrective action plans for protection system single points of failure in combination with three-phase faults if planning studies indicate potential cascading."[13] The Commission seeks comments on its proposals. The Commission also seeks specific comments on the cost and implementation issues associated with its proposed standard modification directive.[14]

II. COMMENTS

NERC supports the Commission's proposal to approve Reliability Standard TPL-001-5. Proposed Reliability Standard TPL-001-5 addresses the Commission's directives from Order No. 786 and would require entities to perform a risk-based assessment of the potential impacts of Protection System single points of failure that could pose a risk to reliability. NERC maintains that the record developed to date supports the continued treatment of the revised Protection System single point of failure with three-phase fault scenario as a TPL-001 Table 1 extreme event, subject to the same evaluation requirements that are applicable to all extreme event studies that indicate

---

[11] *See id.* at PP 18-26. The Commission cites NERC's Petition, a 2009 NERC Industry Advisory, a 2012 NERC informational filing, and draft materials prepared by the TPL-001-5 standard drafting team as providing support for its concern.

[12] *See* Proposed Reliability Standard TPL-001-5 Requirement R4.2, Ex. A to the Petition.

[13] NOPR at P 17.

[14] *Id*. at P 29 ("While we are aware of the potential for increased cost under this proposal, we understand that there are likely cost-effective actions that could be taken to mitigate a protection system single point of failure in combination with a three-phase fault. . . . To better understand the potential for increased costs and other implementation issues, the Commission seeks comment on how many corrective action plans are expected for protection system single points of failure in combination with a three-phase fault if study results indicate potential cascading.").

potential Cascading. For these reasons, which are explained more fully below, NERC does not support the Commission's proposal to direct further revisions to the standard.

A. The Proposed Standard is Technically Justified, Supported by the Record, and Should be Approved as Proposed.

As NERC explained in detail in its Petition, proposed Reliability Standard TPL-001-5 carries forward the risk-based mitigation framework of the TPL-001 standard for the revised Protection System single point of failure planning studies. Consistent with other planning events in the standard, proposed Reliability Standard TPL-001-5 would continue to require the entity to develop a Corrective Action Plan if the entity's system is unable to meet the standard's performance requirements as a result of the revised Table 1, Category P5 (single line-to-ground fault) planning event. Consistent with other extreme events in the standard, the proposed standard would continue to require the entity to study the potential impacts on its system and potential mitigation measures if Cascading would occur as a result of the revised Table 1, Stability 2.e-h (three-phase fault) extreme event.[15]

The proposed standard's approach to the study of Protection System single points of failure is consistent with the recommendations of the SPCS/SAMS report. In this report, the SPCS and SAMS conducted an in-depth analysis of data on Protection System single points of failure collected through a mandatory data request issued by NERC and concluded that a reliability risk existed that needed to be addressed. Based on its analysis of the collected data, this report concluded as follows:

> Analysis of the data demonstrates the existence of a reliability risk associated with single points of failure in protection systems that warrants further action. The analysis shows that the risk from single point of failure is not an endemic problem and instances of single point of failure exposure are lower on higher voltage systems. However, the risk is sufficient to warrant further action. Risk-based

[15] *See* Petition at 24-27.

> assessment should be used to identify protection systems of concern (i.e., locations on the BES where there is a susceptibility to cascading if a protection system single point of failure exists). Not all failures adversely affect reliable operation of the bulk power system. The reliability risk varies based on which component of a protection system fails.[16]

The SPCS/SAMS considered several alternatives to address the potential risk of a Protection System single point of failure with three-phase fault. It considered recommending modifying the TPL-001 standard to add a new planning event, but concluded that the "[p]robability of three-phase fault with a protection system failure is low enough that it does not warrant a planning event."[17] The SPCS/SAMS thus concluded:

> Additional emphasis in planning studies should be placed on assessment of three-phase faults involving protection system single points of failure. ***This concern (the study of protection system single points of failure) is appropriately addressed as an extreme event in TPL-001-4 Part 4.5.*** From TPL-001-4, Part 4.5: 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.[18]

The stakeholder consensus, as developed through NERC's open and inclusive, American National Standards Institute-accredited standard development process, is that the approach recommended by the SPCS/SAMS is the most appropriate and cost effective way to address this issue in planning studies based on all relevant considerations.[19]

---

16 SPCS/SAMS Report at 11.

17 *Id.* at 9.

18 *Id.* at 11 (emphasis added).

19 For comments indicating support for this approach, *see, e.g.*, Petition, Ex. G (Summary of Development and Complete Record of Development) at page at 1601 of pdf:

> The purpose of the SAMS/SPCS joint report was to evaluate the available data and make a recommendation as to the level of reliability risk that did, or did not, exist, and recommend paths forward to address those risks. Industry provided the data for the Section 1600 data request dutifully and faithfully entrusting SPCS and SAMS to carefully anyalze [sic] that data and make reasonable recommendations to industry, NERC and FERC based on the evidence. This is what SPCS and

NERC has identified no information in the record of development that compels a different result. Further, NERC's data indicates that only 10 potential instances of a Protection System single point of failure with three-phase fault have been reported since 2011.[20] While the Commission suggests that such events may "reasonably be viewed as regular occurrences" based on the average frequency with which these events have been reported across the United States,[21] it does not follow that an individual planning entity may expect to experience such an event on its system at that rate. As discussed below, many stakeholders participating in NERC's standard development process indicated that they believed the probability for such an event was too low, the potential costs of mitigation too high, and the potential benefits too uncertain, to mandate that they develop a Corrective Action Plan to address potential performance concerns.

For these reasons, and as explained more fully in its Petition, NERC submits that the standard is technically justified and supported by the record and respectfully requests that the Commission approve it as proposed.

B. The Standard Development Record Does Not Provide Sufficient Support for the Commission's Proposed Standard Modification Directive.

In the NOPR, the Commission states that the record indicates that there is a reliability gap for the Protection System single point of failure with three-phase fault scenario.[22] As the Commission observes, the TPL-001-5 standard drafting team did consider other approaches

---

> SAMS did. The joint report concluded a Planning level event was not warranted and made recommendations to ensure that Protection system failures with three phase faults were studied as extreme events."

See also Petition, Ex. G at pages 568-69, 571, 573-74, 578-79, 582, 586-88, 589-92 (2 comments), 1589, 1595-96, and 1600 of pdf.

[20] Petition at 26-27.

[21] *See* NOPR at P 20 (stating that such events have occurred, on average, once in every eight months according to NERC's data).

[22] *Id*. at PP 18-26.

beyond that recommended by the SPCS/SAMS report in developing the proposed standard.[23] The standard drafting team in fact proposed three alternative approaches. In its first draft, the standard drafting team proposed to require entities to develop a Corrective Action Plan in the event the three-phase fault scenario indicated Cascading.[24] In its second draft, the standard drafting team proposed a provision that, while not called a Corrective Action Plan, would have required entities to develop a list of deficiencies, list actions to prevent Cascading, and provide a timetable for implementation.[25] In its third draft, the standard drafting team proposed to create a new Category P8 planning event for the Protection System single point of failure with three-phase fault scenario.[26] Based on the comments received in response to these proposals during NERC's standard development process, NERC does not believe that the record, as it has been developed to date, provides sufficient support for the Commission's proposed standard modification directive.

During the standard development process, multiple stakeholders expressed disagreement with the standard drafting team's proposals. Stakeholders stated that adding new requirements for Corrective Action Plans would be inconsistent with the existing TPL-001 risk-based framework, which affords planning entities discretion on how best to address extreme event performance issues on their systems.[27] Stakeholders also objected to the re-categorization of the three-phase fault

---

[23] *See id.* at P 21 ("[T]he standard drafting team evaluated and initially adopted more robust options to mitigate protection system single points of failure in combination with three-phase faults if studies indicated cascading, including requiring a corrective action plan or some variation of a corrective action plan.").

[24] *See* Petition, Ex. G at page 407 of pdf (redline comparison of TPL-001-4 and TPL-001-5 draft 1, Apr. 2017).

[25] *See id.* at page 858 of pdf (redline comparison of TPL-001-4 and TPL-001-5 draft 2, Sept. 2017).

[26] *See id.* at page 1406 of pdf (redline comparison of TPL-001-4 and TPL-001-5 draft 3, Feb. 2018).

[27] For comments on the first draft, *see, e.g.*, Petition, Ex. G at page 580 of pdf ("From our perspective, requiring the development of corrective action plans to include redundant relaying for extreme events is inconsistent compared with the existing TPL-001-4 requirements. Corrective action plans should include upgrades to meet planned events and local transmission planning criteria, but not for extreme events that have a very low probability of occurrence."). *See also id.* at pages 570, 572, and 596-97 of pdf (stating that such a requirement "goes beyond the basic criteria for the design, planning and operation of the BES."). *See also id.* at page 582 ("There is no justification given for why

scenario as a planning event, stating that such an approach was not technically justified.[28] Further, stakeholders expressed concern that the costs or other considerations associated with a mandatory Corrective Action Plan or other mitigation requirement for the three-phase fault scenario would be unreasonable in light of the expected reliability benefit, given the lower probability of such an event.[29] Of particular concern, it was suggested that a mandatory mitigation requirement for this

---

these particular extreme events should have more stringent requirements than other extreme events."). *See also id.* at pages 583, 586, 590, and 592 of pdf.

For comments on the second draft, *see, e.g.*, Petition, Ex. G at page 1016 of pdf ("In the past, the decision to mitigate extreme events has been left to the discretion of the Planning Coordinator. The PC is best able to set their risk tolerance or do a cost/benefit analysis to determine whether the Corrective Action Plan should be implemented.")

[28] *See, e.g.*, Petition, Ex. G at page 1591 of pdf ("In reviewing the Cost Effectiveness document, the Technical Rationale, the SPCS/SAMS Order 754 Report, and the proposed redline to the existing TPL-001 Reliability Standard, [commenter] does not believe that the proposed P8 Planning Event is prudent and the technical rationale is flawed in light of what the SPCS/SAMS documented in their review of the Order 754 Data Request analysis.")

See also id. at page 1601 of pdf:

> "Elevating an event to a Planning event when data does not suggest this is warranted creates complexity and confusion and puts other events at risk of the same fate and changes aspects of the planning standard that were working well and did not need to be changed."

[29] For comments on the first draft, *see, e.g.*, Petition, Ex. G at page 574 of pdf ("The 'only' Corrective Action Plan for these kinds of events is a new capital improvement project which will require a significant time and effort for coordination among PCs, TPs and the Facility owners and operators (TO/ TOP/ GO/ GOP). In addition, the installation/implementation of such Corrective Action Plans may cost the industry tens of billions of dollars with significant construction efforts spanning 10-20 years."). Additional comments included the following:

- "Requiring documentation of a CAP for a specific, limited subset of Extreme Events results in a compliance burden that does not provide commensurate reliability benefits" (*Id.* at page 571 of pdf);
- "Requiring a CAP on an extreme contingency on the amount of BES substations involved will lead to unreasonable mitigation costs" (*Id.* at page 583 of pdf);
- "Requiring implementation of a corrective action plan to fix these extremely rare events would cause a large and unnecessary financial burden with little benefit to our system reliability" (*Id.* at page 593 of pdf);
- "Not economically justifiable to require corrective action plans for low probability extreme events like these" (*Id.* at page 593 of PDF); and
- "There are concerns with requiring the development of Corrective Action Plans (CAPs) for extreme stability 2e-2h events, or any other extreme events. The distinction between developing CAPs for 'planning events' and not for 'extreme events' is to recognize that the probability of extreme events is too low and the cost to benefit ratio is too high to require the development of CAPs." (*Id.* at page 595 of pdf).

For comments on the second draft, *see, e.g.*, Petition, Ex. G at page 1019 of pdf ("[I]t is clear that, despite stakeholder input, Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are still requiring a CAP even though the contingencies to be addressed are extreme, unlikely to occur, difficult and expensive to address, and unlikely to significantly improve reliability.").

For comments on the third draft, *see, e.g.*, *id.* at page 1591 of pdf:

scenario could inadvertently result in worse outcomes for reliability, such as by leading to a rise in Protection System Misoperations while entities redesign their Protection Systems to eliminate single points of failure or by forcing entities to direct resources away from more pressing reliability needs.[30]

In summary, comments submitted during NERC's standard development process have indicated that replacing the existing evaluation requirement with a mandatory Corrective Action Plan requirement for the revised Protection System single point of failure with three-phase fault scenario may not advance prudent system planning, in light of the low probability of such an event, the possibility that mitigation could come with high costs and undesirable impacts on planning and operations, and the uncertain reliability benefits that may be gained.

Based on these concerns, NERC does not believe that the record, as developed to date, provides sufficient support for the Commission's proposed directive to require a Corrective Action Plan for the Protection System single point of failure with three-phase fault scenario. NERC respectfully submits that if the Commission is inclined to adopt its NOPR proposal, it should do so only after it has further studied the issue and developed a complete and comprehensive consideration of all relevant factors, including the probable costs, likely reliability benefits, and other potential impacts on operations and planning. NERC believes that such an evaluation is

> [T]he SDT and the SPCS/SAMS clearly recognize that a three-phase fault is in and of itself an event that has a low probability of occurrence, and adding a low probabilistic single point of failure of a protection system on top and requiring that this be analyzed as a Planning Event is beyond prudent planning and results in diminishing returns from an analysis and cost effectiveness standpoint.

[30] *See*, *e.g.*, Petition, Ex. G at page 1022 of pdf (second posting):

> [T]here is risk with the proposed changes of the single point of failure (SPF) language that will not significantly improve reliability. There is likelihood this change may even reduce reliability by having the CAPs force entities to redirect its limited resources away from other important reliability needs to solve SPF identified issue. Further, implementation of the CAPs may likely cause significant mis-ops while system protection systems are being modified to eliminate SPFs thus reducing reliability and increase risk to the transmission system.

needed to ensure that any directed revisions to the NERC Reliability Standards will continue to advance the prudent, risk-based planning of the BPS.

III. CONCLUSION

NERC respectfully requests that the Commission accept these comments for consideration.

Respectfully submitted,

/s/ Lauren A. Perotti

Lauren A. Perotti
Senior Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
lauren.perotti@nerc.net

Counsel for the North American Electric Reliability Corporation

Date: August 26, 2019

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 26th day of August, 2019.

/s/ Lauren A. Perotti

Lauren A. Perotti

Counsel for the North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

JOINT PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND WESTERN ELECTRICITY COORDINATING COUNCIL FOR APPROVAL OF PROPOSED REGIONAL RELIABILITY STANDARD BAL-002-WECC-3

Steve Goodwill
Vice President, General Counsel, and
Corporate Secretary
Ruben Arredondo
Senior Legal Counsel
Western Electricity Coordinating Council
155 North 400 West, Suite 200
Salt Lake City, UT 84103
(801) 582-0353
sgoodwill@wecc.org
rarredondo@wecc.org

Counsel for the Western Electricity Coordinating Council

Lauren Perotti
Senior Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
lauren.perotti@nerc.net

Counsel for the North American Electric Reliability Corporation

September 6, 2019

TABLE OF CONTENTS

I. SUMMARY 3

II. NOTICES AND COMMUNICATIONS 5

III. BACKGROUND 5

A. Regulatory Framework 5

B. WECC Regional Reliability Standards Development Process 7

C. Procedural History 8

D. Development of Proposed Regional Reliability Standard BAL-002-WECC-3 9

IV. JUSTIFICATION FOR APPROVAL 10

A. Purpose and Applicability 10

B. Retirement of Requirement R2 11

C. Enforceability of Proposed Regional Reliability Standard BAL-002-WECC-3 15

V. EFFECTIVE DATE 16

VI. CONCLUSION 17

Exhibit A Proposed Regional Reliability Standard BAL-002-WECC-3 – Contingency Reserve

Exhibit A-1: Clean

Exhibit A-2: Redline to BAL-002-WECC-2a

Exhibit B Implementation Plan

Exhibit C Field Test Results, WECC-0115 BAL-002-WECC-2a Request to Retire Requirement R2

Exhibit D Order No. 672 Criteria

Exhibit E Summary of Development History and Complete Record of Development

Exhibit F Drafting Team Roster

Exhibit G VRF and VSL Justification

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

JOINT PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND WESTERN ELECTRICITY COORDINATING COUNCIL FOR APPROVAL OF PROPOSED REGIONAL RELIABILITY STANDARD BAL-002-WECC-3

Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] and the Western Electricity Coordinating Council ("WECC") hereby submit proposed Regional Reliability Standard BAL-002-WECC-3 – Contingency Reserve for Commission approval. Proposed Regional Reliability Standard BAL-002-WECC-3 reflects the retirement of Requirement R2 in the currently effective standard BAL-002-WECC-2a relating to the composition of the required Contingency Reserve.

NERC and WECC request that the Commission approve proposed Regional Reliability Standard BAL-002-WECC-3 (**Exhibit A**) as just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC and WECC also request approval of the associated

[1] 16 U.S.C. § 824o (2018).

[2] 18 C.F.R. § 39.5 (2018).

[3] 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).

Unless otherwise indicated, capitalized terms used in this Petition shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary"), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf, or Appendix 2 to the NERC Rules of Procedure, *Definitions Used in the NERC Rules of Procedure*, https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

implementation plan (**Exhibit B**) as detailed in this petition, and the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (**Exhibit A**), which remain unchanged from currently effective Regional Reliability Standard BAL-002-WECC-2a (*see* **Exhibit G**).

As required by Section 39.5(a)[4] of the Commission's regulations, this petition presents the technical basis and purpose of proposed Regional Reliability Standard BAL-002-WECC-3, a summary of the development proceedings (**Section III.D** and **Exhibit E**), and a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[5] (**Exhibit D**). Proposed Regional Reliability Standard BAL-002-WECC-3 was approved by the WECC Board of Directors on June 19, 2019 and adopted by the NERC Board of Trustees on August 15, 2019.

I. SUMMARY

The purpose of currently effective Regional Reliability Standard BAL-002-WECC-2a – Contingency Reserve is to provide a Regional Reliability Standard that specifies the quantity and types of Contingency Reserve[6] required to ensure reliability under normal and abnormal

---

[4] 18 C.F.R. § 39.5(a).

[5] The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, at PP 262, 321-37 ("Order No. 672"), *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006).

[6] Contingency Reserve is defined in the NERC Glossary as:

> The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:
>
> • is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.
>
> • is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.

conditions. The standard consists of four requirements. Requirement R1 provides that each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, and that the Contingency Reserve shall consist of any combination of a list of specified reserve types. Requirement R2 provides that at least half of the minimum amount of Contingency Reserve shall be Operating Reserve – Spinning that meets certain reserve characteristics. Requirements R3 and R4 require entities to maintain a minimum amount of Operating Reserve.

Since the regional standard was originally developed, a continent-wide Reliability Standard has come into effect that renders Regional Reliability Standard BAL-002-WECC-2a Requirement R2 redundant and no longer needed for reliability in the Western Interconnection. Reliability Standard BAL-003-1.1 Requirement R1 provides that each Frequency Response Sharing Group or Balancing Authority shall achieve an annual Frequency Response Measure that is equal to or more negative than its Frequency Response Obligation to ensure that it is providing sufficient Frequency Response. This continent-wide requirement helps ensure that sufficient Frequency Response is provided to maintain Interconnection frequency in support of the reliable operation of the Interconnection. In light of this continent-wide Reliability Standard, and as supported by the results of a field test (*see* **Exhibit C**), WECC has determined that Requirement R2 of currently effective Regional Reliability Standard BAL-002-WECC-2a should be retired.

For these reasons, and as discussed more fully herein, NERC and WECC respectfully request the Commission approve proposed Regional Reliability Standard BAL-002-WECC-3 and the associated elements. The following petition presents the justification for approval and supporting documentation.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[7]

Steve Goodwill*
Vice President, General Counsel, and
Corporate Secretary
Ruben Arredondo*
Senior Legal Counsel
Steve Rueckert*
Director of Standards
Western Electricity Coordinating Council
155 North 400 West, Suite 200
Salt Lake City, UT 84103
(801) 582-0353
sgoodwill@wecc.org
rarredondo@wecc.org
srueckert@wecc.org

Lauren Perotti*
Senior Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
lauren.perotti@nerc.net

III. BACKGROUND

The following background information is provided below: (a) an explanation of the regulatory framework for NERC and Regional Reliability Standards; (b) an explanation of the WECC Regional Reliability Standards development process; and (c) a summary of the development process for the proposed Reliability Standard.

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[8] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duties of certifying an ERO that would be charged with developing and

[7] 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, to allow the inclusion of more than two persons on the service list in this proceeding.

[8] 16 U.S.C. § 824o.

enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[9] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[10] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[11] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[12] and Section 39.5(c)[13] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

Similarly, the Commission approves regional differences proposed by Regional Entities, such as Regional Reliability Standards and Variances, if the regional difference is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[14] In addition, Commission Order No. 672 requires further criteria for regional differences. A regional difference from a continent-wide Reliability Standard must either be: (1) more stringent than the continent-wide

---

9 *Id*. § 824o(b)(1).

10 *Id*. § 824o(d)(5).

11 18 C.F.R. § 39.5(a).

12 16 U.S.C. § 824o(d)(2).

13 18 C.F.R. § 39.5(c)(1).

14 16 U.S.C. § 824o(d)(2) and 18 C.F.R. § 39.5(a).

Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; or (2) necessitated by a physical difference in the Bulk-Power System.[15] The Commission must give due weight to the technical expertise of a Regional Entity, like WECC, that is organized on an Interconnection-wide basis with respect to a regional difference to be applicable within that Interconnection.[16]

B. WECC Regional Reliability Standards Development Process

Proposed Regional Reliability Standard BAL-002-WECC-3 was developed in an open and fair manner and in accordance with the Commission-approved WECC Reliability Standards Development Procedures ("RSDP").[17] WECC's RSDP provides for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Regional Reliability Standards and thus addresses several of the Commission's criteria for approving Reliability Standards. The development process is open to any person or entity that is an interested stakeholder. WECC considers the comments of all stakeholders, and a vote of stakeholders and the WECC Board of Directors is required to approve a WECC Regional Reliability Standard or Variance. NERC posts each Regional Reliability Standard or Variance developed by a Regional Entity such as WECC for an additional comment period. The NERC Board of Trustees must adopt a proposed Regional Reliability Standard or Variance before it is submitted to the Commission for approval.

---

15 Order No. 672 at P 291.

16 *Id*. at P 344.

17 The currently effective WECC RSDP was approved by the Commission on October 27, 2017 (s*ee N. Am. Elec. Reliability Corp.*, RR17-5-000 (Oct. 27, 2017) (delegated letter order)) and is available at https://www.nerc.com/FilingsOrders/us/Regional%20Delegation%20Agreements%20DL/WECC%20RSDP_20171027.pdf.

C. Procedural History

The Commission approved Regional Reliability Standard BAL-002-WECC-2 – Contingency Reserve in Order No. 789, issued on November 21, 2013.[18] In approving the regional standard, the Commission found that it contained a more stringent set of requirements than those provided in the continent-wide disturbance control standard in effect at that time, Reliability Standard BAL-002-1 – Disturbance Control Performance.[19] On January 24, 2017, the Commission approved NERC's petition for approval of BAL-002-WECC-2a, which added an interpretation to Requirement R2.[20]

Since the BAL-002-WECC-2 standard was originally approved, the Commission has approved several continent-wide BAL Reliability Standards. The Commission approved the current version of the continent-wide disturbance control standard, Reliability Standard BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, in 2018.[21] Relevant to the proposal described in this petition, the Commission also approved Reliability Standard BAL-003-1 – Frequency Response and Frequency Bias Setting in 2014 in Order No. 794.[22] (The Commission subsequently approved errata version BAL-003-1.1 on November 13, 2015.[23]) In accordance with the approved implementation plan, Reliability Standard BAL-003-1.1 Requirement R1 became effective in the United States on April 1, 2016.

---

[18] *Regional Reliability Standard BAL-002-WECC-2 – Contingency Reserve*, Order No. 789, 145 FERC ¶ 61,141 at P 1 (2013).

[19] *Id.* at P 26.

[20] *N. Am. Elec. Reliability Corp.*, Docket No. RD17-3-000 (Jan. 24, 2017) (delegated letter order).

[21] *N. Am. Elec. Reliability Corp.*, Docket No. RD18-7-000 (Sep. 25, 2018) (delegated letter order).

[22] *Frequency Response and Frequency Bias Setting Reliability Standard*, Order No. 794, 146 FERC ¶ 61,024 (2014).

[23] *N. Am. Elec. Reliability Corp.*, Docket No. RD15-6-000 (Nov. 13, 2015) (delegated letter order).

D. Development of Proposed Regional Reliability Standard BAL-002-WECC-3

As further described in **Exhibit E** hereto, WECC developed proposed Regional Reliability Standard BAL-002-WECC-3 in accordance with the WECC RSDP. On May 6, 2015, WECC received a Standard Authorization Request to retire Requirement R2 of the regional standard on the basis that the regional requirement would become redundant upon the April 1, 2016 effective date of continent-wide Reliability Standard BAL-003-1.1 Requirement R1. The WECC drafting team (**Exhibit F**) consisted of individuals with relevant expertise in the subject matter area.

From May 1, 2017 through April 30, 2018, WECC conducted a field test to evaluate whether the retirement of Requirement R2 would impact reliability in the Western Interconnection.[24] As discussed more fully in **Exhibit C** and summarized below, WECC determined that the retirement of Requirement R2 would have no adverse impact on reliability. The WECC standard drafting team drafted proposed Regional Reliability Standard BAL-002-WECC-3 to reflect the retirement of Requirement R2.

On April 11, 2019, the WECC ballot body approved the proposed Regional Reliability Standard with a 100 percent weighted affirmative vote at 89.5 percent quorum. The WECC Board of Directors approved the proposed Regional Reliability Standard on June 19, 2019. NERC posted the Regional Reliability Standard for a 45-day comment period from June 20, 2019 through August 5, 2019. Commenters agreed that WECC's process was open, inclusive, balanced, and transparent, and that it provided due process. The NERC Board of Trustees adopted proposed Regional Reliability Standard BAL-002-WECC-3 on August 15, 2019.

[24] As WECC did not have a separate procedure for the conduct of field tests, WECC conducted the field test in accordance with the processes specified in Section 6.2 of the then-effective NERC Standard Processes Manual, Appendix 3A to the NERC Rules of Procedure. As part of this field test, WECC (with NERC approval) provided each responsible entity with a waiver of compliance for Requirement R2.

IV. JUSTIFICATION FOR APPROVAL

This section provides a description of the purpose and applicability of proposed Reliability Standard BAL-002-WECC-3, a summary of the changes reflected in the proposed standard, and a discussion of the enforceability of the proposed standard. As discussed more fully below, the main change in the proposed standard is the retirement of Requirement R2. NERC and WECC propose to retire Requirement R2 because the requirement became redundant and no longer necessary for reliability upon the April 1, 2016 effective date of continent-wide Reliability Standard BAL-003-1.1 Requirement R1. Proposed Regional Reliability Standard BAL-002-WECC-3 continues to represent a more stringent set of requirements for entities in the Western Interconnection than those found in the continent-wide disturbance control standard, Reliability Standard BAL-002-3, and it continues to remain necessary for reliability within the Interconnection.

A. Purpose and Applicability

The stated purpose of proposed Regional Reliability Standard BAL-002-WECC-3, which remains unchanged from the currently effective version, is "to specify the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions." The proposed Regional Reliability Standard applies to Balancing Authorities and Reserve Sharing Groups, which is unchanged from the currently effective version.

B. Summary of Revisions

In proposed Regional Reliability Standard BAL-002-WECC-3, the text of Requirement R2 is struck in its entirety and replaced with the word "Reserved." Corresponding revisions are made to the measures and VSL table, and the approved Interpretation to Requirement R2 is removed from Section E., Interpretations. Additionally, minor editorial and formatting changes are made throughout the document. These changes are shown in redline in **Exhibit A**.

C. Retirement of Requirement R2

As noted above, proposed Regional Reliability Standard BAL-002-WECC-3 reflects the retirement of Requirement R2 of the currently effective standard. Regional Reliability Standard BAL-002-WECC-2a Requirement R2 provides:

> R2. Each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve identified in Requirement R1, as Operating Reserve – Spinning that meets both of the following reserve characteristics.
>
> 2.1 Reserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system;
>
> 2.2 Reserve that is capable of fully responding within ten minutes.

A similar version of this requirement was present in the first version of the regional standard, WECC-BAL-STD-002-0, which was approved by the Commission in 2007.[25] The original intent of this requirement was to: (1) aid in frequency recovery (through governor action) for large generation loss events across the Western Interconnection; and (2) provide a part of the Contingency Reserves for generation trip events within the Balancing Authority or Reserve Sharing Group area. It was based on a historical, pre-Reliability Standards paradigm in which visibility, data exchange, and understanding of other Balancing Authority areas was minimal, frequency deviation was largely addressed by manual and analog intervention, and coordination between Balancing Authority areas was accomplished through mutual cooperation unsupported by mandatory standards.

Regional Reliability Standard WECC-BAL-STD-002-0 carried forward criteria from the Reliability Management System ("RMS") of WECC's predecessor, the Western Systems

[25] *N. Am. Elec. Reliability Corp*., 119 FERC ¶ 61,260 (2007).

Coordinating Council ("WSCC"). The RMS program was comprised of approximately 17 "criteria" that came from the NERC Operating Policies. When the initial set of NERC's Version 0 standards was developed, WSCC reviewed the standards to determine if the RMS criteria had been included. Where an RMS criterion was not addressed in a continent-wide standard, WSCC initiated development of a Regional Reliability Standard to transition the RMS criteria to a mandatory standard. The criteria and language from RMS had to be translated to a requirement in the Regional Reliability Standard without revision. In some instances, the RMS criteria were more stringent than the continent-wide requirements. This included the criteria carried forward in WECC-BAL-STD-002-0.

During the development of the RMS criteria in the late 1990s, WSCC did not conduct any simulations or assessments to determine or identify that the 50 percent level that was later specified in BAL-002-WECC Requirement R2 was what was needed for optimal system reliability. Rather, it was an agreed upon value established by a majority of the RMS drafters. While it could be assumed that a 100 percent level would be best, such a requirement would have come with unacceptably high costs. Conversely, a requirement to carry zero percent would have been unacceptable from a reliability perspective. In the end, most the participants gravitated to the number in the middle, 50 percent. There was no other technical analysis done.

In the intervening years, NERC developed a continent-wide Reliability Standard specifically to address frequency response. The stated purpose of Reliability Standard BAL-003-1.1 is "[t]o require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value" and "[t]o provide consistent methods for measuring Frequency Response and determining the Frequency Bias

Setting." Requirement R1, which became mandatory and enforceable on entities in the United States on April 1, 2016, provides as follows:

> R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation.

Reliability Standard BAL-003-1.1 addresses the same frequency response components covered in currently effective Regional Reliability Standard BAL-002-WECC-2a Requirement R2 but in a results-based manner. Requirement R2 of the regional standard requires the entity to maintain at least half of its Contingency Reserve as Operating Reserve – Spinning. By contrast, Reliability Standard BAL-003-1.1 requires the entity to achieve a calculated Frequency Response Measure and allows the entity to meet this measure through a variety of services or arrangements. The WECC standard drafting team determined that retention of the regional minimum Operating Reserve – Spinning requirement, alongside the continent-wide frequency response requirement, could lead to confusion and the needless procurement of additional reserves, thereby increasing costs without providing additional reliability benefits.

To evaluate the potential impact on reliability in the Western Interconnection should Requirement R2 be retired, WECC conducted a field test from May 1, 2017 through April 30, 2018, the results of which are summarized below and discussed in detail in **Exhibit C**. To provide more accurate results, WECC, with NERC approval, provided a compliance waiver for Requirement R2 to responsible entities. As part of the field test, responsible entities provided the following information: (1) for any reportable Disturbance Control Standard ("DCS") event, the

date and time of the event, the required amount of Contingency Reserves at the time of the event, the actual amount of Operating Reserves – Spinning at the time of the event, and the actual DCS performance; and (2) for all instances of a loss of resources 700 megawatts ("MW") or greater, whether it is a reportable DCS event or not, the date and time of the event, the name of the resource(s), and the total MW loss.

To evaluate the resulting impacts on reliability, the WECC standard drafting team applied two metrics. The first metric, DCS performance, monitored the performance of each Reserve Sharing Group/Balancing Authority for every reportable DCS event to see whether any were unable to meet the DCS recovery period for a DCS event. The second metric evaluated system performance for any loss of resources greater than 700 MW and for any adverse impact on frequency response.

As discussed more fully in **Exhibit C**, analysis of the data demonstrates that all 66 DCS events occurring during the field test period had a 100 percent pass rate, showing no degradation to DCS performance. Entities carried and deployed enough reserves for post disturbance Area Control Error recovery. For 63 of the total 66 events, entities carried more than the required 50 percent Operating Reserve – Spinning (on average, 166.38 percent). For the remaining three events, entities carried less than 50 percent Operating Reserve – Spinning (on average, 5.3 percent less).[26]

Western Interconnection frequency performance was assessed to further determine the impact of the field test on the Interconnection. Frequency performance data was collected for the 32 events having a verified resource loss of more than 700 MW. NERC's Essential Reliability Services Measure 4 describes a comprehensive set of frequency response measures capturing speed

[26] **Exhibit C**, Field Test Report at 6-8.

of frequency response and response withdrawal at all relevant time frames; these measures were used to analyze the collected data.[27] The WECC standard drafting team's analysis also included frequency response information from the 2018 NERC State of Reliability Report.[28] The standard drafting team's analysis indicated that frequency response performance did not degrade in the Western Interconnection during the field test period.[29]

Based on the results of the field test, the WECC standard drafting team determined that the retirement of Requirement R2 is unlikely to have an adverse impact on reliability in the Western Interconnection.[30] In light of these results, and in consideration of the redundancy with continent-wide Reliability Standard BAL-003-1.1, it is appropriate to retire Requirement R2 in the BAL-002-WECC regional standard.

D. Enforceability of Proposed Regional Reliability Standard BAL-002-WECC-3

Proposed Regional Reliability Standard BAL-002-WECC-3 includes VRFs and VSLs. The VSLs provide guidance on the way that NERC will enforce the requirements of the proposed Reliability Standard. The VRFs are one of several elements used to determine an appropriate sanction when the associated requirement is violated. The VRFs assess the impact to reliability of violating a specific requirement. The VRFs and VSLs for the three remaining requirements in proposed Regional Reliability Standard BAL-002-WECC-3 are unchanged from the currently effective version of the standard.

---

[27] **Exhibit C**, Field Test Report at 8. For additional description of these measures, *see* NERC, *Essential Reliability Services Task Force Measures Framework Report* (Nov. 2015), https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.

[28] *See* **Exhibit C**, Field Test Report at 9-10 (citing 2018 NERC State of Reliability Report at Table 2.1).

[29] **Exhibit C**, Field Test Report at 8-10.

[30] *Id.* at 2.

The proposed Regional Reliability Standard also includes measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[31] The measures for the three remaining requirements in proposed Regional Reliability Standard BAL-002-WECC-3 are unchanged from the currently effective version of the standard.

V. EFFECTIVE DATE

NERC respectfully requests that the Commission approve the proposed implementation plan, provided in **Exhibit B** hereto. Because the only substantive change in the proposed standard is the retirement of Requirement R2, the proposed implementation plan provides that proposed Regional Reliability Standard BAL-002-WECC-3 would become effective immediately upon regulatory approval.

[31] Order No. 672 at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

VI. CONCLUSION

For the reasons set forth above, NERC and WECC respectfully request that the Commission approve:

- proposed Regional Reliability Standard BAL-002-WECC-3 and the other associated elements, including the VRFs and VSLs, included in **Exhibit A**;
- the proposed implementation plan, included in **Exhibit B**; and
- the retirement of currently effective Regional Reliability Standard BAL-002-WECC-2a.

Respectfully submitted,

/s/ Lauren Perotti

Steve Goodwill
Vice President, General Counsel, and
Corporate Secretary
Ruben Arredondo
Senior Legal Counsel
Western Electricity Coordinating Council
155 North 400 West, Suite 200
Salt Lake City, UT 84103
(801) 582-0353
sgoodwill@wecc.org
rarredondo@wecc.org

Counsel for the Western Electricity Coordinating Council

Lauren Perotti
Senior Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
lauren.perotti@nerc.net

Counsel for the North American Electric Reliability Corporation

Date: September 6, 2019

Exhibit A

Proposed Regional Reliability Standard
BAL-002-WECC-3 – Contingency Reserve

A. Introduction

1. Title: **Contingency Reserve**

2. Number: BAL-002-WECC-3

3. Purpose: To specify the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions.

4. Applicability:

4.1. Functional Entities:

4.1.1 Balancing Authority

4.1.1.1 The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Reserve Sharing Group, in which case, the Reserve Sharing Group becomes the responsible entity.

4.1.2 Reserve Sharing Group

4.1.2.1 The Reserve Sharing Group when comprised of a Source Balancing Authority becomes the source Reserve Sharing Group.

4.1.2.2 The Reserve Sharing Group when comprised of a Sink Balancing Authority becomes the sink Reserve Sharing Group.

5. Effective Date: Immediately upon receipt of regulatory approval.

B. Requirements and Measures

R1. Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve, that is*: [Violation Risk Factor: High] [Time Horizon: Real-time operations]*

1.1. The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

1.2. Composed of any combination of the reserve types specified below:

- Operating Reserve—Spinning
- Operating Reserve—Supplemental
- Interchange Transactions designated by the Source Balancing Authority as Operating Reserve—Supplemental

- Reserve held by other entities by agreement that is deliverable on Firm Transmission Service
- A resource, other than generation or load, that can provide energy or reduce energy consumption
- Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement.
- All other load, not identified above, once the Reliability Coordinator has declared an energy emergency alert signifying that firm load interruption is imminent or in progress.

1.3. Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464).

1.4. An amount of capacity from a resource that is deployable within ten minutes.

M1. Each Balancing Authority and each Reserve Sharing Group will have documentation demonstrating its Contingency Reserve was maintained, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Part 1.1

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates its Contingency Reserve was maintained in accordance with the amounts identified in Requirement R1, Part 1.1, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Attachment A is a practical illustration showing how the generation amount may be calculated under Requirement R1.

- Where Dynamic Schedules are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1 may include, but is not limited to, documentation showing a reciprocal acknowledgement as to which entity is carrying the reserves. This transfer may be all or some portion of the physical generator and is not limited to the entire physical capability of the generator.
- Where Pseudo-Ties are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1, may include, but is not limited to, documentation accounting for the transfers included in the Pseudo-Ties.

Part 1.2

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.2.

Evidence may include, but is not limited to, documentation that reserves were comprised of the types listed in Requirement R1, Part 1.2 for purposes of meeting the Contingency Reserve obligation of Requirement R1. Additionally, for purposes of the last bullet of Requirement R1, Part 1.2, evidence of compliance may include, but is not limited to, documentation that the reliability coordinator had issued an energy emergency alert, indicating that firm Load interruption was imminent or was in progress.

Part 1.3

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.3. Evidence of compliance with Requirement R1, Part 1.3 may include, but is not limited to, documentation that Contingency Reserve amounts are based upon load and generating data averaged over each Clock Hour and excludes Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464.

Part 1.4

Evidence of compliance with Requirement R1, Part 1.4 may include, but is not limited to, documentation that the reserves maintained to comply with Requirement R1, Part 1.4 are fully deployable within ten minutes.

R2. Reserved.

M2. Reserved.

R3. Each Sink Balancing Authority and each sink Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, except within the first sixty minutes following an event requiring the activation of Contingency Reserve. [*Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M3. Each Sink Balancing Authority and each sink Reserve Sharing Group will have dated documentation demonstrating it maintained an amount of Operating Reserve, in addition to the Contingency Reserve identified in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, for the entire period of the transaction, except within the first sixty minutes following an event requiring the activation of Contingency Reserves, in accordance with Requirement 3.

R4. Each Source Balancing Authority and each source Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve amounts identified in Requirement R1, equal to the amount and type of

Operating Reserves for any Operating Reserve transactions for which it is the Source Balancing Authority or source Reserve Sharing Group. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M4. Each Source Balancing Authority and each source Reserve Sharing Group will have dated documentation that demonstrates it maintained an amount of additional Operating Reserves identified in Requirement R1, greater than or equal to the amount and type of that identified in Requirement 4, for the entire period of the transaction.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot-Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

Each Balancing Authority and each Reserve Sharing Group shall keep evidence for Requirement R1 through R4 for three years plus calendar current.

1.4. Additional Compliance Information:

1.4.1 This Standard shall apply to each Balancing Authority and each Reserve Sharing Group that has registered with WECC as provided in Part 1.4.2 of Section C.

Each Balancing Authority identified in the registration with WECC as provided in Part 1.4.2 of Section C shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

1.4.2 A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC: 1) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, 2) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and 3) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

1.4.3 If an agent properly designated in accordance with Part 1.4.2 of Section C identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance: 1) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, 2) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection 1) of this Part 1.4.3 of Section C, and 3) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection 1) of this Part 1.4.3 of Section C (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

1.4.4 If an agent properly designated in accordance with Part 1.4.2 of Section C fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be

the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

1.4.5 Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Part 1.4.2 of Section C shall be subject to this Standard on an individual basis.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.
R2.	Reserved.			
R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R3.
R4.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which

	Contingency Reserve Operating Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R4.	Contingency Reserve Operating Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R4.	Contingency Reserve Operating Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R4.	Contingency Reserve Operating Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	October 29, 2008	Adopted by NERC Board of Trustees	
1	October 21, 2010	Order issued remanding BAL-002-WECC-1	
2	November 7, 2012	Adopted by NERC Board of Trustees	
2	November 21, 2013	FERC Order issued approving BAL-002-WECC-2. (Order becomes effective 1/28/14.)	
2a	December 1, 2015	Approved by WECC Board of Directors	Clarified resources available for use in Requirement R2
2a	January 24, 2017	FERC approved	The Interpretation provides clarification regarding the types of resources that may be used to satisfy Contingency Reserve.
3	TBD	TBD	The Interpretation was removed. Requirement R2 was deleted. Template and formatting were updated. Syntax and verb tense in Guideline section were corrected.

Standard Attachments

Attachment A

Attachment A is illustrative only; it is not a requirement. Requirement R1 calls for an amount of Contingency Reserve to be maintained, predicated on an amount of generation and load required in Requirement R1, Part 1.1., specifically:

"**1.1** The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation."

Attachment A illustrates one possible way to account for and calculate the amount of generation upon which the Contingency Reserve amount is predicated.

Below is a practical illustration showing how the generation amount may be calculated under Requirement R1 for Balancing Authorities (BA) and Reserve Sharing Groups (RSG).

BA1 / RSG 1	**Generation**	**Part of Generator**
Generator 1	300 MWs online	Yes
Generator 2	200 MWs online	Yes
Generator 3 (Pseudo-Tied out to BA2)	100 MWs online	No
Generator 4 QF (has backup contract)	10 MWs online	No
Generator 5 QF in EMS	10 MWs online	Yes
Generator 6	0 MWs online	Yes
Dynamic Schedule to BA2 from BA1[1]	(50 MWs)	
Generation	620 MWs	(The sum of gen 1–6)
BA generation (EMS)	510 MWs	(The sum of gen 1, 2, and 5)
Generation to use Under BAL-002-WECC-1	460 MWs**	(The sum of gen 1, 2, and 5 minus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would maintain reserves based on 510 MWs Generation.

BA2 / RSG2	**Generation**	**Part of Generator**
Generator 11	100 MWs	Yes
Generator 12	100 MWs	Yes
Generator 3 (Pseudo-Tied in from BA1)	100 MWs	Yes
Dynamic Schedule from BA1 to BA2	50 MWs	Yes
Generation	300 MWs	(The sum of gen 11, 12 and 3.)
BA generation (EMS)	300 MWs	(The sum of gen 11, 12 and 3)

[1] Note: This Dynamic Schedule is not the same as the Generator 3 Pseudo-Tie.

Generation to use Under BAL-002-WECC-1	350 MWs**	(The sum of gen 11, 12 and 3 plus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would have to maintain reserves based on 510MWs Generation and BA2 would determine its generation to be 300 MWs.

Guideline and Technical Basis

A Guidance Document addressing implementation of this standard was filed with Version 2.

A. Introduction

1. Title: **Contingency Reserve**

2. Number: BAL-002-WECC-~~2a~~3

3. Purpose: To specify the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions.

4. Applicability:

4.1. Functional Entities:

4.1.1 Balancing Authority

~~4.1.1.2~~4.1.1.1 ~~4.1.1.~~ The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Reserve Sharing Group, in which case, the Reserve Sharing Group becomes the responsible entity.

4.1.2 Reserve Sharing Group

~~4.1.2.2~~4.1.2.1 ~~4.2.1.~~ The Reserve Sharing Group when comprised of a Source Balancing Authority becomes the source Reserve Sharing Group.

~~4.1.2.4~~4.1.2.2 ~~4.2.2.~~ The Reserve Sharing Group when comprised of a Sink Balancing Authority becomes the sink Reserve Sharing Group.

~~6.~~5. ~~5.~~ Effective Date: ~~On the first day~~ Immediately upon receipt of ~~the third quarter following applicable~~ regulatory approval.

B. Requirements and Measures

~~R2.~~R1. **~~R1.~~** Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes

following an event requiring the activation of Contingency Reserve, that is*: [Violation Risk Factor: High] [Time Horizon: Real-time operations]*

~~2.2.~~1.1. ~~1.1~~ The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

~~2.4.~~1.2. ~~1.2~~ ~~Comprised~~Composed of any combination of the reserve types specified below:

- Operating Reserve ~~–~~ Spinning
- Operating Reserve ~~–~~ Supplemental
- Interchange Transactions designated by the Source Balancing Authority as Operating Reserve ~~–~~ Supplemental
- Reserve held by other entities by agreement that is deliverable on Firm Transmission Service
- A resource, other than generation or load, that can provide energy or reduce energy consumption
- Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement.
- All other load, not identified above, once the Reliability Coordinator has declared an energy emergency alert signifying that firm load interruption is imminent or in progress.

~~2.6.~~1.3. ~~1.3~~ Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464).

~~2.8.~~1.4. ~~1.4~~ An amount of capacity from a resource that is deployable within ten minutes.

~~M2.~~M1. ~~M1.~~ Each Balancing Authority and each Reserve Sharing Group will have documentation demonstrating its Contingency Reserve was maintained, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Part 1.1

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates its Contingency Reserve was maintained in accordance with the amounts identified in Requirement R1, Part 1.1, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Attachment A is a practical illustration showing how the generation amount may be calculated under Requirement R1.

- Where Dynamic Schedules are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1 may include, but is not limited to, documentation showing a reciprocal acknowledgement as to which entity is carrying the reserves. This transfer may be all or some portion of the physical generator and is not limited to the entire physical capability of the generator.
- Where Pseudo-Ties are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1, may include, but is not limited to, documentation accounting for the transfers included in the Pseudo-Ties.

Part 1.2

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.2. Evidence may include, but is not limited to, documentation that reserves were comprised of the types listed in Requirement R1, Part 1.2 for purposes of meeting the Contingency Reserve obligation of Requirement R1. Additionally, for purposes of the last bullet of Requirement R1, Part 1.2, evidence of compliance may include, but is not limited to, documentation that the reliability coordinator had issued an energy emergency alert, indicating that firm Load interruption was imminent or was in progress.

Part 1.3

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.3. Evidence of compliance with Requirement R1, Part 1.3 may include, but is not limited

to, documentation that Contingency Reserve amounts are based upon load and generating data averaged over each Clock Hour and excludes Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464.

Part 1.4

Evidence of compliance with Requirement R1, Part 1.4 may include, but is not limited to, documentation that the reserves maintained to comply with Requirement R1, Part 1.4 are fully deployable within ten minutes.

~~**R2.** Each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve identified in Requirement R1, as Operating Reserve – Spinning that meets both of the following reserve characteristics. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*~~

~~**2.1** Reserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system;~~

~~**2.2** Reserve that is capable of fully responding within ten minutes.~~

~~**M2.** Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates it maintained at least half of the Contingency Reserve identified in Requirement R1 as Operating Reserve – Spinning, averaged over each Clock Hour, that met both of the reserve characteristics identified in Requirement R2, Part 2.1 and Requirement R2, Part 2.2.~~

R2. ~~**R3.**~~ Reserved.

M2. Reserved.

R3. Each Sink Balancing Authority and each sink Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, except within the first sixty minutes following an event requiring the activation of Contingency Reserve. [*Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M3. ~~**M3.**~~ Each Sink Balancing Authority and each sink Reserve Sharing Group will have dated documentation demonstrating it maintained an amount of Operating Reserve, in addition to the Contingency Reserve identified in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction

designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, for the entire period of the transaction, except within the first sixty minutes following an event requiring the activation of Contingency Reserves, in accordance with Requirement 3.

R4. ~~**R4.**~~ Each Source Balancing Authority and each source Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve amounts identified in Requirement R1, equal to the amount and type of Operating Reserves for any Operating Reserve transactions for which it is the Source Balancing Authority or source Reserve Sharing Group. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M4. ~~**M4.**~~ Each Source Balancing Authority and each source Reserve Sharing Group will have dated documentation that demonstrates it maintained an amount of additional Operating Reserves identified in Requirement R1, greater than or equal to the amount and type of that identified in Requirement 4, for the entire period of the transaction.

C. Compliance

1. ~~**1.**~~ **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority:

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2. ~~**1.2**~~ ~~—~~ **Compliance Monitoring and Assessment Processes:**

Compliance Audit

Self-Certification

Spot-Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. ~~1.3~~ Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

Each Balancing Authority and each Reserve Sharing Group shall keep evidence for Requirement R1 through R4 for three years plus calendar current.

1.4. ~~1.4.~~ Additional Compliance Information:

1.4.1 ~~1.4.1.~~ This Standard shall apply to each Balancing Authority and each Reserve Sharing Group that has registered with WECC as provided in Part 1.4.2 of Section C.

Each Balancing Authority identified in the registration with WECC as provided in Part 1.4.2 of Section C shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

1.4.2 ~~1.4.2.~~ A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC: 1) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, 2) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and 3) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

1.4.3 ~~**1.4.3.**~~ If an agent properly designated in accordance with Part 1.4.2 of Section C identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance: 1) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, 2) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection 1) of this Part 1.4.3 of Section C, and 3) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection 1) of this Part 1.4.3 of Section C (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

1.4.4 ~~**1.4.4.**~~ If an agent properly designated in accordance with Part 1.4.2 of Section C fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

1.4.5 ~~**1.4.5.**~~ Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Part 1.4.2 of Section C shall be subject to this Standard on an individual basis.

~~**Table of Compliance Elements**~~

Violation Severity Levels

R #	2. ~~Time Horizon~~	3. ~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	4. ~~Real-time Operations~~	5. ~~High~~	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Contingency Reserve amount, with the characteristics specified in	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Contingency Reserve amount, with the characteristics specified in	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Contingency Reserve amount, with the characteristics specified in	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.

			Requirement R1.	Requirement R1.	Requirement R1.			
R2.			~~Real-time Operations~~ Reserved.	~~High~~	~~The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve – Spinning is less than 100% but greater than or equal to 90% of the required Operating Reserve – Spinning amount specified in Requirement R2, and both~~	~~The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve – Spinning is less than 90% but greater than or equal to 80% of the required Operating Reserve – Spinning amount specified in Requirement R2, and both~~	~~The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve – Spinning is less than 80% but greater than or equal to 70% of the required Operating Reserve – Spinning amount specified in Requirement R2, and both characteristics~~	**6.**	~~The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve – Spinning is less than 70% of the required Operating Reserve – Spinning amount specified in Requirement R2, and both characteristics were met.~~

					~~characteristics were met.~~	~~characteristics were met.~~	~~were met.~~	
R3.	~~Real-time Operations~~	**7.** ~~High~~	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R3.		
R4.	~~Real-time Operations~~	**8.** ~~High~~	The Balancing Authority or the Reserve Sharing	The Balancing Authority or the Reserve Sharing	The Balancing Authority or the Reserve Sharing	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating Reserve is less		

			Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R4.	Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R4.	Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R4.	than 70% of the required Operating Reserve amount specified in Requirement R4.

D. ~~D.~~ Regional Variances

None.

E. E. Interpretations

Interpretation Requested

Arizona Public Service (APS) sought clarification that for purposes of BAL-002-WECC-2, Requirement R2, APS and other Balancing Authorities and/or Reserve Sharing Groups can include "technologies, such as batteries, both contemplated and not yet contemplated…as potential resources [to meet the Operating Reserve – Spinning requirement of BAL-002-WECC-2, Requirement R2] – so long as the…resource can meet the response characteristics described in the standard."

A standards interpretation team comprised of members of the original BAL drafting team concluded that APS' understanding was correct.

"[N]on-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" so long as they meet the technical and performance requirements in Requirement R2 (i.e., that the resources must be immediately and automatically responsive to frequency deviations through the action of a control system and capable of fully responding within ten minutes).[1]

In Order 789, Paragraph 48, the Federal Energy Regulatory Commission (Commission) responded to the California Independent System Operator that:

Commission Determination

[1] FERC Order 789, P47. July 18, 2013.

See also FERC Order 740, Section E, Demand-Side Management as a Resource, at P 50:
"The Commission clarified that the purpose of this directive was to ensure comparable treatment of demand-side management with conventional generation or any other technology and to allow demand-side management to be considered as a resource for contingency reserves on this basis without requiring the use of any particular contingency reserve option."

~~48. The Commission determines that non-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" provided those resources satisfy the technical and performance requirements in Requirement R2. Our determination is supported by the standard drafting team's response to a comment during the standard drafting process where the standard drafting team stated that "technologies, such as batteries, both contemplated and not yet contemplated are included in the standard as potential resources – so long as the undefined resource can meet the response characteristics described in the standard …The language does not preclude any specific technology; rather, the language delineates how that technology must [] respond."[2] We also note that non-traditional resources could contribute to contingency reserve under the regional Reliability Standard if they are resources, "other than generation or load, that can provide energy or reduce energy consumption."~~

[2] ~~"Fn 44 Petition, Exhibit C at 20."~~

~~F.~~ None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	October 29, 2008	Adopted by NERC Board of Trustees	
1	October 21, 2010	Order issued remanding BAL-002-WECC-1	
2	November 7, 2012	Adopted by NERC Board of Trustees	
2	November 21, 2013	FERC Order issued approving BAL-002-WECC-2. (Order becomes effective 1/28/14.)	
2a	December 1, 2015	Approved by WECC Board of Directors	Clarified resources available for use in Requirement R2
2a	January 24, 2017	FERC approved	The Interpretation provides clarification regarding the types of resources that may be used to satisfy Contingency Reserve.
3	TBD	TBD	The Interpretation was removed. Requirement R2 was deleted. Template and formatting were updated. Syntax and verb tense in Guideline section were corrected.

Standard Attachments

Attachment A

Attachment A is illustrative only; it is not a requirement. Requirement R1 calls for an amount of Contingency Reserve to be maintained, predicated on an amount of generation and load required in Requirement R1, Part 1.1., specifically:

"**1.1** The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation."

Attachment A illustrates one possible way to account for and calculate the amount of generation upon which the Contingency Reserve amount is predicated.

Below is a practical illustration showing how the generation amount may be calculated under Requirement R1 for Balancing Authorities (BA) and Reserve Sharing Groups (RSG).

BA1 / RSG 1	**Generation**	**Part of Generator**
Generator 1	300 MWs online	Yes
Generator 2	200 MWs online	Yes
Generator 3 (Pseudo-Tied out to BA2)	100 MWs online	No
Generator 4 QF (has backup contract)	10 MWs online	No
Generator 5 QF in EMS	10 MWs online	Yes
Generator 6	0 MWs online	Yes
Dynamic Schedule to BA2 from BA1[3]	(50 MWs)	
Generation	620 MWs	(The sum of gen 1—6)
BA generation (EMS)	510 MWs	(The sum of gen 1, 2, and 5)
Generation to use Under BAL-002-WECC-1	460 MWs**	(The sum of gen 1, 2, and 5 minus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would maintain reserves based on 510 MWs Generation.

BA2 / RSG2	**Generation**	**Part of Generator**
Generator 11	100 MWs	Yes
Generator 12	100 MWs	Yes
Generator 3 (Pseudo-Tied in from BA1)	100 MWs	Yes
Dynamic Schedule from BA1 to BA2	50 MWs	Yes
Generation	300 MWs	(The sum of gen 11, 12 and 3.)

[3] Note: This Dynamic Schedule is not the same as the Generator 3 Pseudo-Tie.

BA generation (EMS)	300 MWs	(The sum of gen 11, 12 and 3)
Generation to use Under BAL-002-WECC-1	350 MWs**	(The sum of gen 11, 12 and 3 plus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would have to maintain reserves based on 510MWs Generation and BA2 would determine its generation to be 300 MWs.

Guideline and Technical Basis

A Guidance Document addressing implementation of this standard ~~has been~~was filed with ~~this standard.~~ Version 2.

~~Version History~~

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
~~1~~	~~October 29, 2008~~	~~Adopted by NERC Board of Trustees~~	
~~1~~	~~October 21, 2010~~	~~Order issued remanding BAL-002-WECC-1~~	
~~2~~	~~November 7, 2012~~	~~Adopted by NERC Board of Trustees~~	
~~2~~	~~November 21, 2013~~	~~FERC Order issued approving BAL-002-WECC-2. (Order becomes effective 1/28/14.)~~	
~~2a~~	~~December 1, 2015~~	~~Approved by WECC Board of Directors~~	~~Clarified resources available for use in Requirement R2~~
~~2a~~	~~January 24, 2017~~	~~FERC approved~~	~~The interpretation provides clarification regarding the types of resources that may be used to satisfy Contingency Reserve.~~

Exhibit B

Implementation Plan

Electric Reliability and Security for the West

Exhibit B
Implementation Plan
WECC-0115 BAL-002-WECC-3
Contingency Reserve
Request to Retire R2

Implementation Plan

Standards Authorization Request

The original Standards Authorization Request (SAR) is located here.[1] Documentation templates have been updated for final filing.

Approvals Required

- WECC Board of Directors ..... June 19, 2019
- NERC Board of Trustees..... August 15, 2019
- FERC..... Pending

Effective Date

The WECC-0115 project asserts that BAL-002-WECC-2a,[2] Contingency Reserve, Requirement R2 became redundant to BAL-003-1.1, Frequency Response and Frequency Bias Setting, Requirement R1 effective April 1, 2016**.** Because that date has passed, retirement of BAL-002-WECC-2a, Contingency Reserve, Requirement R2 can be effective immediately on receipt of regulatory approval.

Justification of Effective Date

The reliability-related substance of WECC-0115 BAL-002-WECC-2a Contingency Reserve, Requirement R2 is contained in BAL-003-1.1 Frequency Response and Frequency Bias, Requirement R1. (See Technical Justification, Exhibit C and Response to Comments for Posting 2, Attachment E9.)

Because BAL-003-1.1 Requirement R1 addresses the reliability task, BAL-002-WECC-2a Requirement R2 is redundant and can be retired.

---

[1] Attachment E1 of this filing reflects the SAR in an updated template. The original is located at https://www.wecc.org/Reliability/WECC-0115%20BAL-002-WECC-2%20Contingency%20Reserve%20SAR%20to%20Retire%20Requirement%20R2.pdf

[2] The naming nomenclature changed during development from BAL-002-WECC-2, BAL-002-WECC-2a, and will change to BAL-002-WECC-3 if approved.

Impact on Other Standards

As to other existing and proposed standards, the drafting team (DT) notes that some confusion may arise as to how the retirement of WECC-0115 BAL-002-WECC-2a, Requirement R2 may interplay with the existing BAL-002-1, Disturbance Control Performance standard. BAL-002-1, Requirement R2.3 requires the applicable entity (the Regional Reliability Organization *or* the Reserve Sharing Group) to "specify its Contingency Reserve policies, including … (R2.3) … the permissible mix of Operating Reserve—Spinning and Operating Reserve—Supplemental that may be included in Contingency Reserve." Arguably, BAL-002-WECC-2a Requirement R2 meets this requirement.

The DT disagrees that retention of BAL-002-WECC-2a Requirement R2 is the only way to comply with BAL-002-1. At a high level, since BAL-002-1 has no Measure for the associated Requirement R2, it is unclear how compliance might be met. Further, since the only Measure provided requires that the Balancing Authority *or* the Reserve Sharing Group "shall calculate and report compliance with the Disturbance Control Standard," there is a disconnect between the required performance (have a policy) and the required Measure (perform a calculation).

Consideration of Early Compliance

The DT sees no concerns with early compliance.

Action Plan

On June 19, 2019, the WECC Board of Directors approved the project for further regulatory disposition. The full project is available for review on the WECC website at the WECC-0115 homepage.[3]

[3] https://www.wecc.org/Standards/Pages/WECC-0115.aspx

Exhibit C

Field Test Results, WECC-0115 BAL-002-WECC-2a
Request to Retire Requirement R2

WECC

Field Test Results
WECC-0115 BAL-002-WECC-2a
Request to Retire Requirement R2

Standard Drafting Team

March 5, 2019

Executive Summary

After doing a field test from May 1, 2017, through April 30, 2018, the WECC-0115 BAL-002-WECC-2a, Contingency Reserve, Request to Retire Requirement R2 Drafting Team (DT) concluded that if Requirement R2 is retired, it is unlikely to adversely affect reliability.

On May 6, 2015, WECC received Standard Authorization Request (SAR) WECC-0115 BAL-002-WECC-2a Contingency Reserve, Request to Retire Requirement R2 (R2), requesting retirement of R2 and its compliance elements. The SAR stated that on April 1, 2016, BAL-003-1.1 Frequency Response and Frequency Bias Settings, Requirement R1 would make R2 redundant.

From May 1, 2017, through April 30, 2018, WECC conducted a NERC-approved field test to find out the effect on reliability if R2 was retired.[1] A compliance waiver for R2 was granted beginning on May 1, 2017 and ending on May 1, 2019.

WECC required U.S. entities to provide data on the quantity of reserve carried during the field test period. This was done to enable WECC to see the effects of the field test, as a condition to take part in the field test, and to meet conditions from NERC in approving WECC's request for a field test. The data showed no adverse effect to reliability if R2 is retired.

Project WECC-0115 will not be balloted until this report is presented for review to the WECC Ballot Pool and NERC meets the requirements of the NERC Rules of Procedure, 6.3 Communication and Coordination for All Types of Field Tests and Data Analyses.

[1] NERC approved the field test in late March 2017 and WECC conducted it per NERC Standards Processes Manual, Section 6.2, Field Tests and Data Analysis for Validation of Requirement.

Table of Contents

Introduction **4**

Field Test Description **4**

Data Source and Description 4

Field Test Analysis and Results **5**

Data Description 6

DCS Event Field Test Data ..... **Error! Bookmark not defined.**

Figures

Table 1—DCS Event Field Test Data 6

Figure 1—Table 2.1 from NERC 2018 State of Reliability Report, June 2018 10

Figure 2—A to B IFRM 11

Figure 3—A to C IFRM 12

Figure 4—Cn to C Ratio 13

Figure 5—Table 2.2 from NERC 2018 Frequency Response Annual Analysis, November 2018 14

Figure 6—Cn to UFLS margin 14

Introduction

On May 6, 2015, WECC received SAR WECC-0115 BAL-002-WECC-2a, Contingency Reserve requesting retirement of Requirement R2. The SAR was deemed complete the same day. The SAR asserted that on April 1, 2016, BAL-003-1.1, Frequency Response and Frequency Bias Setting, Requirement R1 would make R2 redundant.

On June 23, 2015, the WECC Standards Committee (WSC) approved the SAR after vetting by the WECC Operating Committee Steering Committee (OC; June 9, 2015) and the Joint Guidance Committee (JGC; May 27, 2015).

From October 22 through December 8, 2015, the project was posted once for comment, during which stakeholders were asked a question:

> Do you agree that WECC Regional Standard BAL-002-WECC-2,[2] Contingency Reserve, Requirement R2 should be retired as of the effective date of NERC Standard BAL-003-1[3] (BAL-003), Frequency Response and Frequency Bias Setting, Requirement R1?

Three entities responded to the posting and were in favor of retirement.[4] After discussion, the DT and WECC staff[5] agreed that a field test should be done to gauge the effect of retiring R2.

A NERC-approved field test was done from May 1, 2017, through April 30, 2018. The field test data is the foundation of this paper and was posted for comment as Posting 2 of this project. Posting 2 received three comments, one for retirement and two suggesting caution.

Field Test Description

Data Source and Description

The field test data was requested from each Balancing Authority (BA) and each Reserve Sharing Group (RSG) subject to R2. WECC received data through an online WECC portal.

The data request included the following information:

[2] During this project, the BAL-002-WECC-2 designation changed to BAL-002-WECC-2a on January 24, 2017, in FERC Docket No. RD17-3-000. The BAL-003-1 designation changed to BAL-003-1.1 on November 13, 2015, in FERC Docket RD15-6-000.

[3] BAL-003-1, Frequency Response and Frequency Bias Setting was approved by FERC on March 24, 2014, and has an enforcement date of April 1, 2016.

[4] Xcel Energy, Bonneville Power Administration, and WECC.

[5] Steven Rueckert, WECC Director of Standards, and Phil O'Donnell, WECC Manager, Operations and Planning Audits and Investigations.

1. For any reportable Disturbance Control Standard (DCS) event, the date and time of the event, the required amount of Contingency Reserves at the time of the event, the actual amount of Operating Reserves-Spinning at the time of the event, and the actual DCS performance.[6]
2. For all instances of a loss of resources 700 MW or greater, whether it is a reportable DCS event or not, the date and time of the event, the name of the resource(s), and the total MW loss.

Objective

The field test was designed to determine whether retirement of R2 would have any adverse effect on grid reliability. The test examined the effect on Disturbance Control Standard (DCS[7]) performance and frequency response in the Western Interconnection.

Overview

The first metric, DCS performance, monitored the performance of each RSG, and each BA that was not a member of an RSG, for every reportable DCS event, to see whether any were unable to meet the DCS recovery period for a DCS event. WECC asked for more information from the participants to calculate the ratio for required contingency reserve to Operating Reserve-Spinning for each qualified event.

The second metric watched system performance for any loss of resources greater than 700 MW and for any adverse effects on frequency response.[8] Data for this metric was collected using the same method NERC uses to collect information to analyze interconnection frequency response for its State of Reliability and Frequency Response Annual Analysis reports.

Field Test Analysis and Results

R2 was intended to do two things: 1) to aid in frequency recovery (through governor action) for large generation loss events across the Western Interconnection, and 2) to provide a part of the Contingency Reserves (on-line generation minus 10-minute response) for generation trip events within the BA or RSG if the party is an RSG member. With new standards being applied and generation resources changing in the Western Interconnection, the SAR was based on the presumptions that R2 became

[6] During the field test, only the DCS responsible entity was asked to provide data during DCS events. Entities that did not have a reportable DCS event were not requested to provide data.

[7] "The reliability standard that sets the time limit following a Disturbance within which a BA must return its Area Control Error to within a specified range." NERC Glossary of Terms Used in Reliability Standards (Glossary).

[8] The DT noted that the WECC Interconnection Frequency Response Obligation (IFRO) is roughly -840 MW per 0.1 HZ. The 700-MW loss was chosen as a more conservative number than the IFRO and represents a value large enough to cause a significant frequency excursion. For an example, see *Frequency Response Analysis Tool*, Dmitry Kosterev, Bonneville Power Administration, 2014. https://www.wecc.org/Reliability/Frequency%20Response%20Analysis%20-%20Dmitry%20Kosterev.pdf

redundant on April 1, 2016—the effective date of BAL-003-1.1—and that, with R2's retirement, neither metrics for the interconnection's frequency performance nor DCS performance would degrade.

With BAL-003-01.1 in effect, frequency response became measurable, and the field test gave entities a compliance waiver for R2, thus splitting DCS and frequency response. Entities were responsible for ensuring both reliability performance metrics were met. On that basis, WECC used the data captured from the field test with interconnection frequency response performance data to assess any effect to individual DCS performance, as well as the overall frequency performance of the interconnection.

Data Description

Data from the field test covered 66 DCS events. During each of those events, entities provided data to help assess DCS performance. This data included Contingency Reserve Obligation, Required Spin (assuming no compliance waiver), Actual Spin, and whether Area Control Error (ACE) recovery was met to successfully pass the DCS event. See Table 1 for the data set collected.

Table 1—DCS Event Field Test Data

Entity #	Reported MW Loss	DCS Event	Contingency (Cont) Reserve Obligation	Required Spin	Actual Spin	Pass(x)	Cont/Spin (Pre-Contingency Value)
Entity 3	530	Yes	585	293	878	x	150.09%
Entity 3	480	Yes	585	293	1165	x	199.15%
Entity 5	341	Yes	2624	1312	5595	x	213.22%
Entity 5	309	Yes	2528	1264	4095	x	161.99%
Entity 5	310	Yes	2830	1415	4428	x	156.47%
Entity 5	294	Yes	2992	1496	4010	x	134.02%
Entity 5	480	Yes	2349	1174.5	4360	x	185.61%
Entity 5	375	Yes	3068	1534	4986	x	162.52%
Entity 5	393	Yes	3106	1553	3989	x	128.43%
Entity 5	587	Yes	2373	1187	4483	x	188.92%
Entity 5	628	Yes	3124	1562	4201	x	134.48%
Entity 5	388	Yes	3211	1606	4217	x	131.33%
Entity 5	838	Yes	2988	1494	4223	x	141.33%
Entity 5	353	Yes	3234	1617	4658	x	144.03%
Entity 2	655	Yes	656	328	552	x	84.26%
Entity 5	356	Yes	3646	1823	5956	x	163.36%
Entity 5	619	Yes	3732	1866	6193	x	165.94%
Entity 2	430	Yes	468	234	417	x	89.11%
Entity 5	513	Yes	3514	1757	6063	x	172.54%
Entity 5	519	Yes	2823	1412	6001	x	212.58%
Entity 5	748	Yes	3688	1844	6271	x	170.04%
Entity 5	630	Yes	3024	1512	6680	x	220.90%
Entity 2	**442**	**Yes**	**538**	**269**	**231**	**x**	**42.97%**

Entity #	Reported MW Loss	DCS Event	Contingency (Cont) Reserve Obligation	Required Spin	Actual Spin	Pass(x)	Cont/Spin (Pre-Contingency Value)
Entity 5	506	Yes	3610	1805	6703	x	185.68%
Entity 5	760	Yes	3742	1871	6133	x	163.90%
Entity 5	522	Yes	3612	1806	5698	x	157.75%
Entity 5	1061	Yes	3791	1896	6799	x	179.35%
Entity 5	411	Yes	2964	1482	5358	x	180.77%
Entity 5	1882	Yes	2497	1249	4952	x	198.32%
Entity 5	486	Yes	3536	1768	5855	x	165.58%
Entity 5	475	Yes	3422	1711	6647	x	194.24%
Entity 5	723	Yes	3006	1503	8401	x	279.47%
Entity 5	796	Yes	3293	1647	5844	x	177.47%
Entity 5	492	Yes	3174	1587	5111	x	161.03%
Entity 5	460	Yes	5129	2565	9318	x	181.67%
Entity 5	398	Yes	5614	2807	11920	x	212.33%
Entity 5	1150	Yes	5231	2616	13142	x	251.23%
Entity 5	1699	Yes	6028	3014	9288	x	154.08%
Entity 5	786	Yes	5874	2937	9350	x	159.18%
Entity 5	479	Yes	5155	2578	14798	x	287.06%
Entity 3	538	Yes	585	293	1329	x	227.23%
Entity 5	714	Yes	5869	2935	11056	x	188.38%
Entity 5	656	Yes	6090	3045	14291	x	234.66%
Entity 5	760	Yes	5517	2759	8679	x	157.31%
Entity 3	790	Yes	790	395	1607	x	203.42%
Entity 2	496	Yes	573	286	379	x	66.15%
Entity 5	1046	Yes	8090	4045	12613	x	155.91%
Entity 5	493	Yes	7099	3550	12659	x	178.32%
Entity 5	651	Yes	3351	1676	5962	x	177.92%
Entity 1	388	Yes	1040	520	979	x	94.13%
Entity 4	851	Yes	2181	1091	1091	x	50.02%
Entity 1	970	Yes	1037	519	1151	x	110.99%
Entity 4	1059	Yes	1175	588	600	x	51.06%
Entity 3	582	Yes	790	395	924	x	116.96%
Entity 2	**800**	**Yes**	**565**	**283**	**234**	**x**	**41.44%**
Entity 1	471	Yes	1040	520	1359	x	130.67%
Entity 1	699	Yes	1041	521	1426	x	136.98%
Entity 4	**817**	**Yes**	**1543**	**772**	**768**	**x**	**49.77%**
Entity 5	1026	Yes	2832	1416	6038	x	213.21%
Entity 5	850	Yes	2741	1371	6543	x	238.71%
Entity 5	660	Yes	2691	1346	5911	x	219.66%
Entity 1	500	Yes	1040	520	1589	x	152.79%

Entity #	Reported MW Loss	DCS Event	Contingency (Cont) Reserve Obligation	Required Spin	Actual Spin	Pass(x)	Cont/Spin (Pre-Contingency Value)
Entity 5	506	Yes	3206	1603	5893	x	183.81%
Entity 5	707	Yes	3056	1528	5952	x	194.76%
Entity 1	322	Yes	1020	510	1454	x	142.55%
Entity 4	866	Yes	1186	593	672	x	56.66%

All 66 events had a 100-percent pass rate showing no degradation to DCS performance. With the R2 compliance waiver in effect, entities carried and deployed enough reserves for post-disturbance ACE recovery. Also, Spinning Reserve more than the required 50 percent was carried during all but three events. Of the remaining 63, on average, the entity was carrying 166.38 percent Spinning Reserve as opposed to 50 percent Spinning Reserve required by the standard. In the remaining three events, the entities carried an average of 5.3 percent less Spinning Reserve than mandated.[9]

WECC assessed Western Interconnection frequency performance to further determine the effect of the field test on the Interconnection. Frequency performance data was collected for the 32 events having a verified resource loss of more than 700 MW.

According to NERC, Essential Reliability Services (ERS) Measure 4[10] is a comprehensive set of Frequency Response measures capturing speed of Frequency Response and response withdrawal at all relevant time frames:

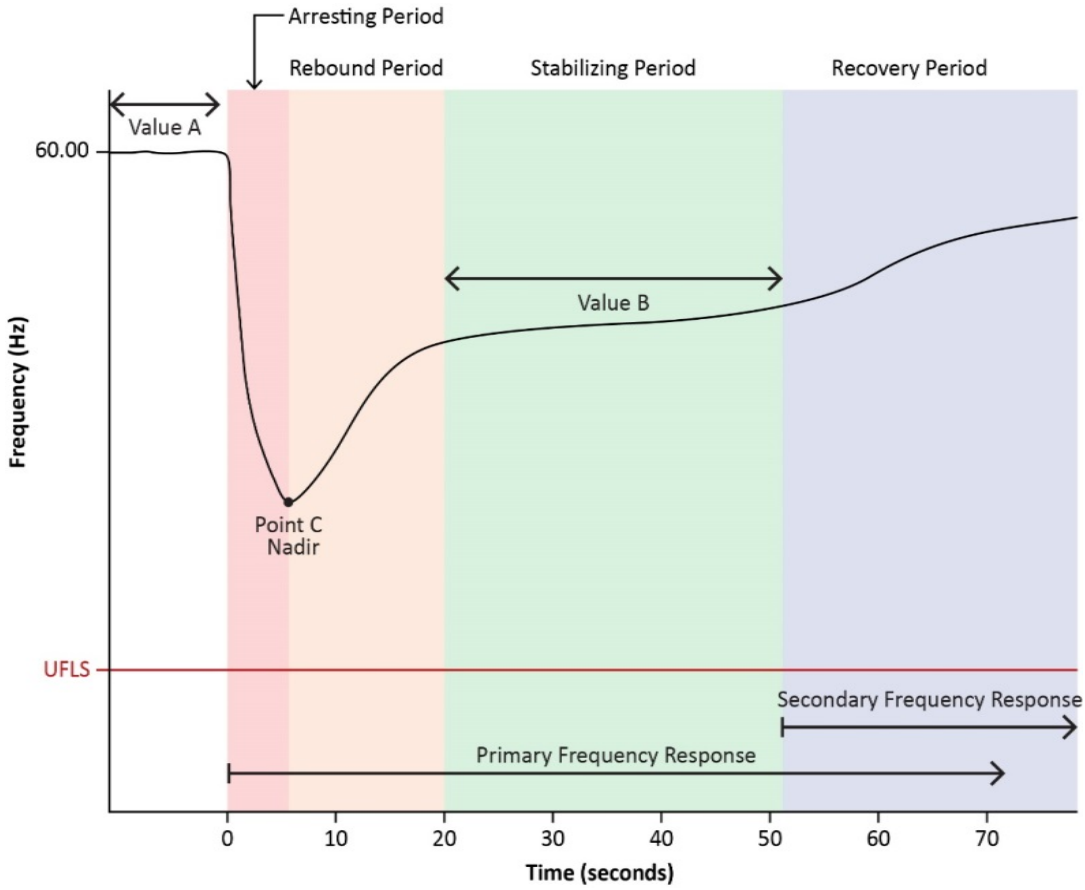
- Point A to C frequency response in MW/0.1 Hz;
- Point A to B frequency response in MW/0.1 Hz (similar to Adequate Level of Reliability (ALR)-12);
- C:B Ratio;
- C:C′ Ratio; and
- Three time-based measures: t0 to tC, tC to tC′, and t0 to tC′.

Figure 1 shows a frequency deviation due to a loss of generation resource and the methodology for calculating frequency response. The event starts at time t0. Value A is the average frequency from t-16 to t-2 seconds, Point C is the lowest frequency point observed in the first 12 seconds, and Value B is the average from t+20 to t+52 seconds. Point C′ occurs when the frequency after 52 seconds falls below either the Point C (12 seconds) or average Value B (20–52 seconds), as illustrated below.

[9] This analysis does not speculate on why reporting entities carried more reserve than required. It only notes that excess reserves were carried.

[10] Please note that, although similar in title, *NERC's Essential Reliability Services (ERS) Measure 4* (page 8) is different from *NERC's State of Reliability Report, Metric M-4* (page 9).

Figure 1—Frequency Deviation due to Loss of Generation Resource



Per the NERC State of Reliability Report, Metric M-4 has two parts of interest: 1) performance of the Western Interconnection to arrest the frequency decline after a loss-of-generation event to prevent activation of underfrequency load shedding (UFLS), and 2) performance of the Western Interconnection to stabilize quickly at a high enough frequency to successfully respond to a second frequency event, should one occur.[11]

- Arresting Period: In 2017, the Western Interconnection experienced an event in which the Point C nadir was 59.697 Hz, resulting in a Point C to UFLS margin of 0.197 Hz, the smallest margin since a 0.171-Hz event in 2014. The resource MW losses for these two events were 2,685 MW and 2,826 MW, respectively. This is more than double the mean resource MW loss for each year and larger than the Resource Contingency Criteria of 2,626 MW, which is defined in the 2016 Frequency Response Annual Analysis and used to calculate 2017 IFRO. Over the 2013–2017 operating years, the Western Interconnection trend was neither statistically improving nor

[11] NERC State of Reliability, June 2018, Appendix E: Frequency Response Statistics and Essential Reliability Services, DADS Metric 4: Performance—Demand Response Events by Month—Dispatched vs. Realized, page 112. https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_2018_SOR_06202018_Final.pdf

declining. This indicates that the BAL-002-WECC-2a field test did not adversely affect Western Interconnection arresting period frequency performance.

- Stabilizing Period: The mean frequency response in 2017 of 1,836 MW/0.1 Hz was the highest of all years evaluated in this report. The Western Interconnection had no events in 2017 in which its interconnection frequency response measure (IFRM) was below its IFRO, including the event noted above, wherein the Point C nadir to UFLS margin was less than 0.200 Hz. Frequency response over the 2013–2017 operating years indicated that the Western Interconnection experienced significant improvement during the stabilizing period. This indicates that the BAL-002-WECC-2a field test did not adversely affect Western Interconnection stabilizing period frequency performance.

Figure 2—Table 2.1 from NERC 2018 State of Reliability Report, June 2018

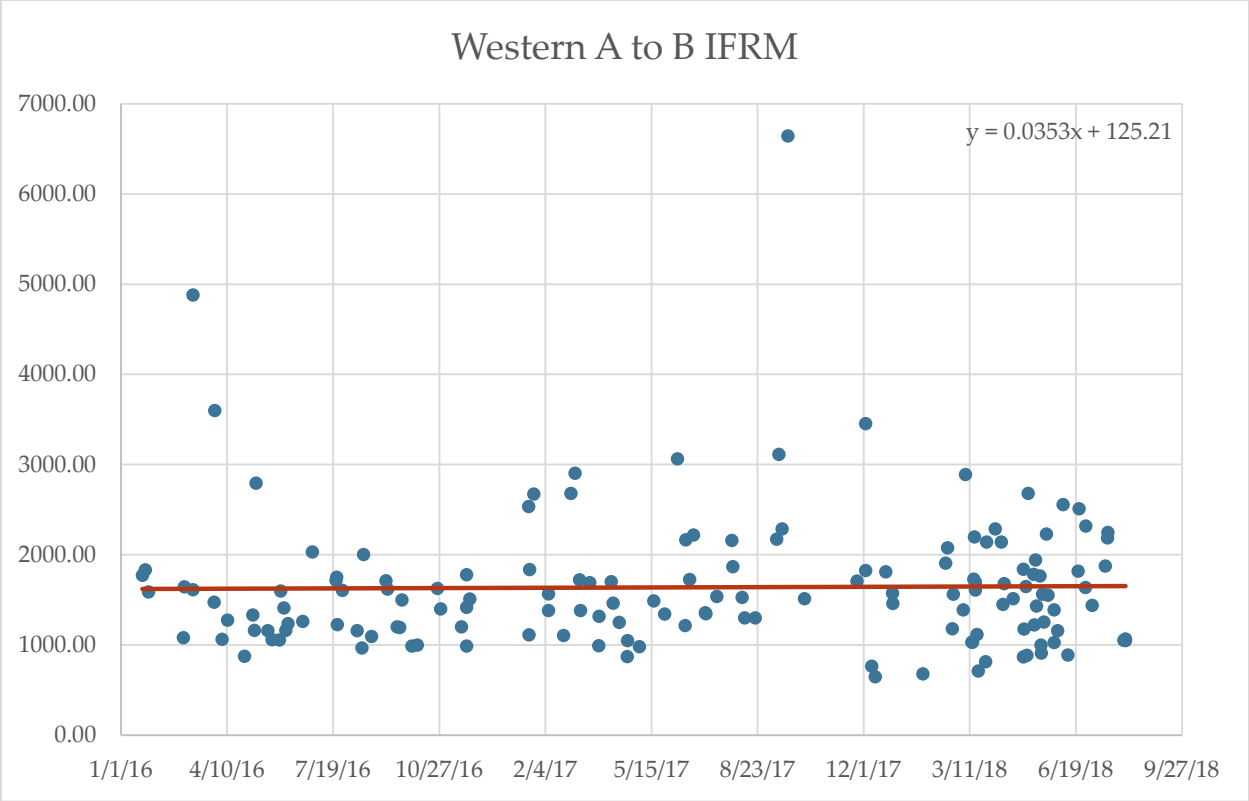
Table 2.1: Interconnection Performance Summary Statistics

Interconnection	2017 OY Largest Resource Loss		2017 OY Lowest A-B IFRM Performance		2013–2017 OY Arresting Period Performance Trend	2013–2017 OY Stabilizing Period Performance Trend
	MW Loss	UFLS Margin (Hz)	MW Loss	UFLS Margin (Hz)		
Eastern	1,661	0.453	511	0.472	Improving	No Change
Texas	1,219	0.433	369	0.603	Improving	Improving
Quebec	954	0.873	314	1.199	Improving	No Change
Western	2,776	0.210	383	0.450	No Change	Improving

Below is a summary of Western Interconnection frequency performance metrics:

1. A to B frequency response shows the effectiveness of primary frequency response in stabilizing frequency after a large frequency excursion. This measure is the conventional means of calculating Frequency Response as the ratio of net MW lost to the difference between Point A and Point B frequency values.

Figure 3—A to B IFRM



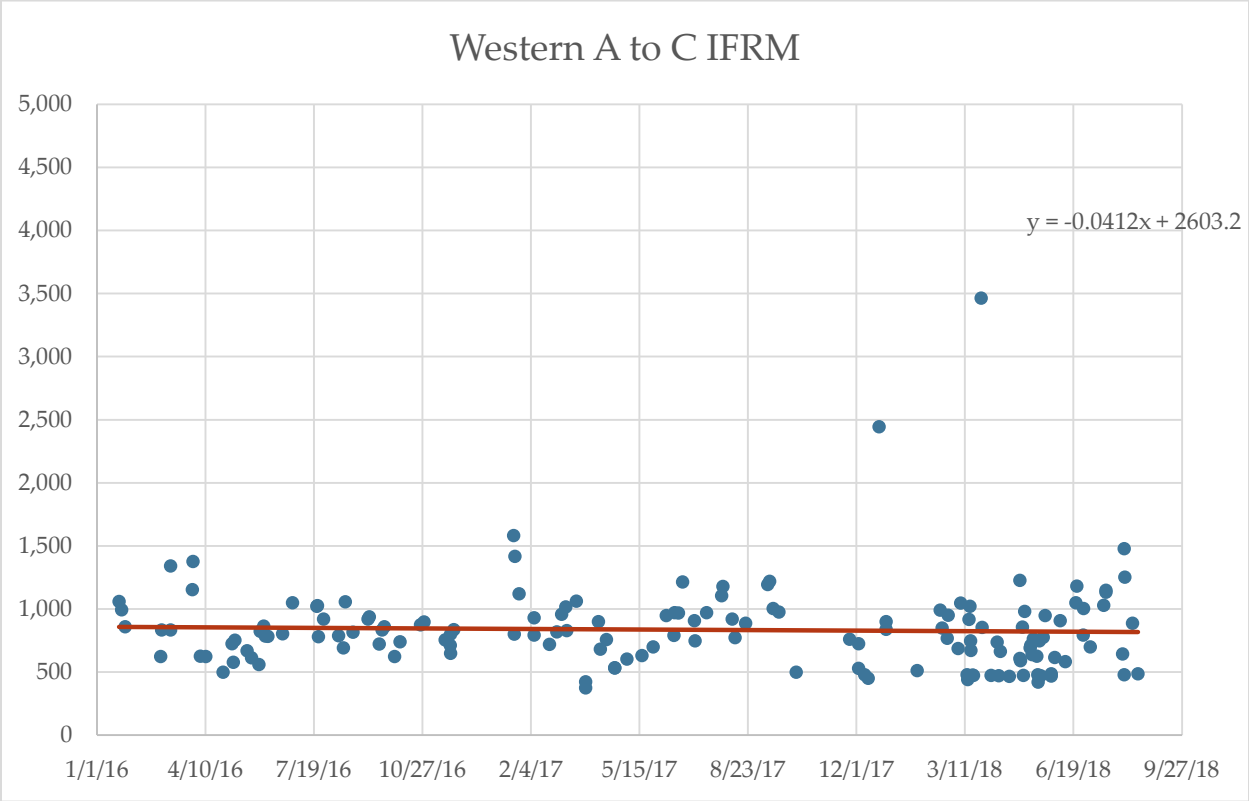
An increasing trend indicates that frequency response is improving. The Western Interconnection A to C metric shows no degradation.

For example:

- 60.0 Hz pre-event (A frequency), Loss of 1,000 MW, 59.9 Hz primary frequency response (B frequency)
  - A to B Measure = 1,000 MW/0.1 HZ
- 60.0 Hz pre-event (A frequency), Loss of 1,500 MW, 59.9 Hz primary frequency response (B frequency)
  - A to B Measure = 1,500 MW/0.1 HZ
  - A to B measure increases, showing that larger loss of resource results in same post-event disturbance
- 60.0 Hz pre-event (A frequency), Loss of 1,000 MW, 59.92 Hz primary frequency response (B frequency)
  - A to B Measure = 1,250 MW/0.1 HZ
  - A to B measure increases, showing that the same loss in resource results in higher post-event (primary frequency response measure)

2. A to C frequency response shows the effects of inertial response, load response (load damping), and initial governor response. Governor response is triggered immediately after frequency exceeds a preset deadband; however, depending on generator technology, full governor response may take up to 30 seconds to fully deploy. This measure is calculated as the ratio of net megawatts lost to the difference between Point A and Point C frequency values.

Figure 4—A to C IFRM



An increasing trend indicates that frequency response is improving. The Western Interconnection A to C metric shows no degradation.

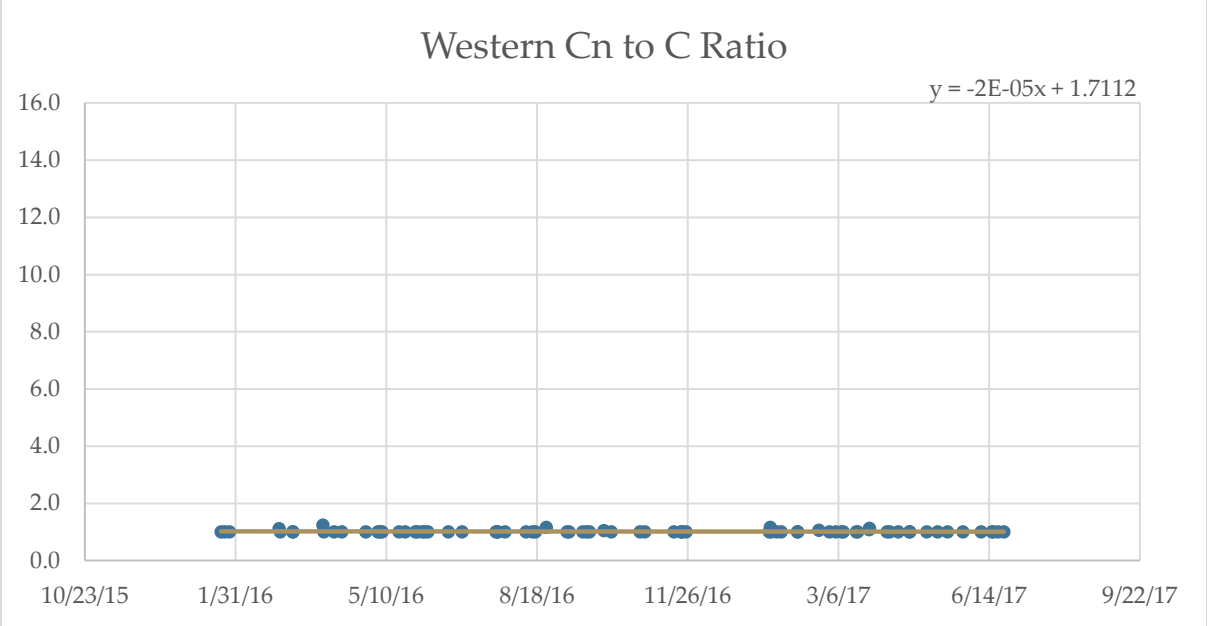
For example:

- 60.0 Hz pre-event (A frequency), Loss of 1000 MW, 59.85 Hz lowest frequency (C frequency)
  - A to C Measure = 667 MW/0.1 HZ
- 60.0 Hz pre-event (A frequency), Loss of 1500 MW, 59.85 Hz lowest frequency (C frequency)
  - A to C Measure = 1000 MW/0.1 HZ
  - A to C measure increases, representing that larger loss of resource results in same post event disturbance

- 60.0 Hz pre-event (A frequency), Loss of 1000 MW, 59.90 Hz lowest frequency (C frequency)
  - A to C Measure = 1000 MW/0.1 HZ
  - A to C measure increases, representing that the same loss in resource results in higher post event (primary frequency response measure)

3. Cn to C is the ratio between the absolute frequency minimum (Point Cn) caused by governor withdrawal and the initial nadir (Point C). This metric measures withdrawal of primary frequency response. A response greater than 1.0 indicates withdrawal. A declining trend is an indication of improving primary frequency response. The Western Interconnection has shown no indications of response withdrawal.

Figure 5—Cn to C Ratio



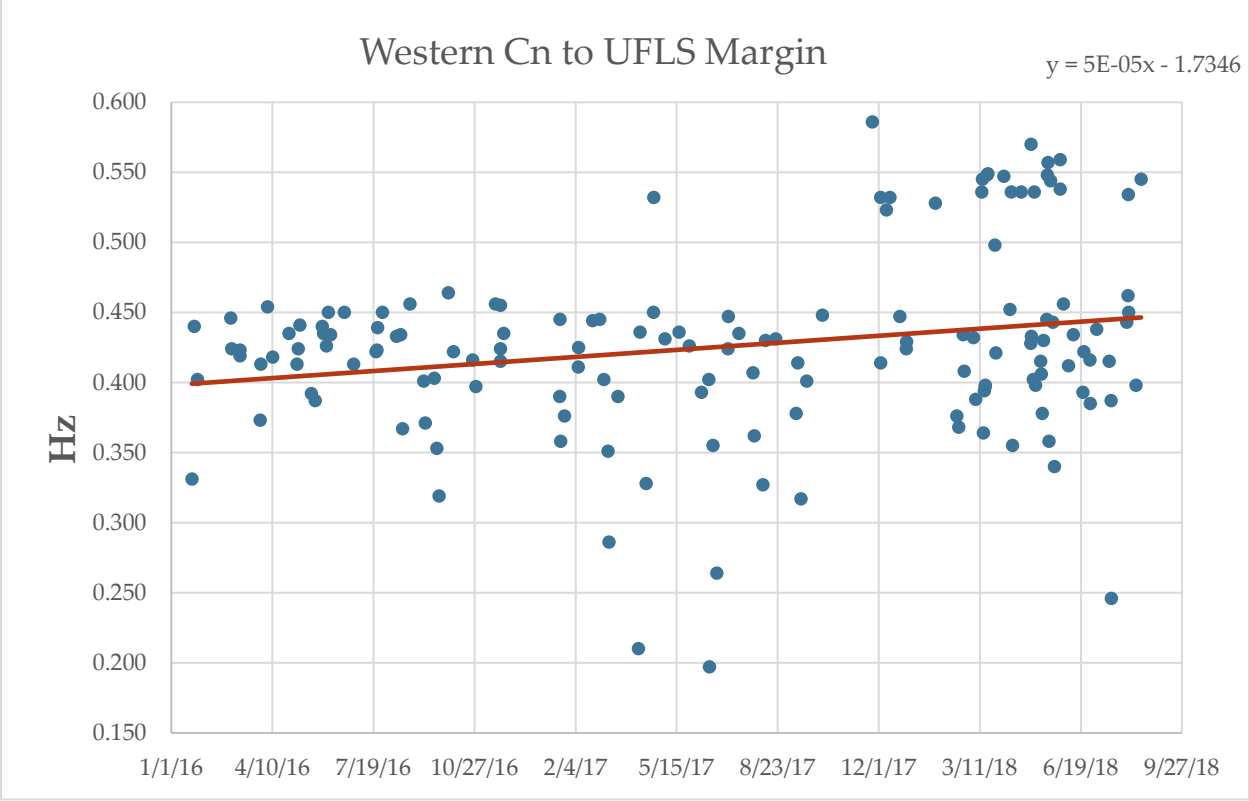
When the DT drafted this white paper, Cn data was only publicly available through August 2017. However, in addition to trended data, the NERC Frequency Response Annual Analysis, published November 2018, also shows that the Western Interconnection continues to experience no frequency response withdrawal during the BAL-002-WECC-2a field test.

Figure 6—Table 2.2 from NERC 2018 Frequency Response Annual Analysis, November 2018

Table 2.2: Statistical Analysis of the Adjustment for C' Nadir (BC'_{adj})						
Interconnection	Number of Events Analyzed	C' Lower than B	C' Lower than C	Mean Difference	Standard Deviation	BC'ADJ (95% Quantile)
Eastern	112	66	34	0.005	0.003	0.006
Western	86	45	0	N/A	N/A	N/A
ERCOT	143	61	2	N/A	N/A	N/A
Québec	135	31	12	-0.019	0.028	-0.004

4. Cn to UFLS ratio measures the margin between the frequency nadir and the first step in UFLS.

Figure 7—Cn to UFLS margin



The trend does show a statistical increase in UFLS margin. Also note that the magnitude of the resource loss directly affects Interconnection performance calculation as measured by IFRMs and Point C to UFLS margins. During 2017 and 2018, there were three events in which the resource loss was 2,776

MW, 2,685 MW, and 2741 MW; more than double the mean resource MW loss for each year and larger than the defined Resource Contingency Criteria of 2,626 MW.[12]

One event occurred on April 6, 2017, 11:00 p.m. PDT when the field test was not in effect and the other two events on June 16, 2017, at 5:14 a.m. PDT and July 18, 2018, at 5:30 p.m. PDT when the field test was in effect. All events, however, had comparable results and significant UFLS margin before and after the field test. Also, all three events had an IFRM that exceeded the IFRO.

Per the WECC Off-Nominal Frequency Load Shedding Plan (UFLSP), load shedding occurs sequentially in five blocks with a minimum separation of 0.1 Hz between steps. UFLS entities taking part in the UFLS plan (aka, Coordinated Plan) must shed their first block of load as soon as frequency has declined to 59.5 Hz.[13]

[12] See the 2017 Frequency Response Annual Analysis https://www.nerc.com/comm/OC/BAL0031_Supporting_Documents_2017_DL/2017_FRAA_Final_20171113.pdf

[13] "UFLS Entities participating in the Coordinated Plan are required to shed their first block of load as soon as frequency has declined to 59.5 Hz, with additional minimum requirements for further load shedding steps" (as set forth in the accompanying table)." WECC Off-Nominal Frequency Load Shedding Plan, Coordinated Plans, P. 1a, page 8, December 5, 2012.

WECC receives data used in its analyses from a wide variety of sources. WECC strives to source its data from reliable entities and undertakes reasonable efforts to validate the accuracy of the data used. WECC believes the data contained herein and used in its analyses is accurate and reliable. However, WECC disclaims any and all representations, guarantees, warranties, and liability for the information contained herein and any use thereof. Persons who use and rely on the information contained herein do so at their own risk.

Exhibit D

Order No. 672 Criteria

Electric Reliability and Security for the West

Exhibit D
Order 672 Criteria
WECC-0115 Contingency Reserve
Request to Retire R2

Introduction

The North American Electric Reliability Corporation (NERC) is responsible for ensuring that the Reliability Standards, Violation Risk Factors (VRF), Violation Severity Levels (VSL), definitions, Variances, and Interpretations developed by drafting teams are developed in accordance with NERC processes. These standards must also meet NERC's benchmarks for Reliability Standards, as well as criteria for governmental approval.

In Federal Energy Regulatory Commission (FERC) Order No. 672,[1] FERC identified criteria that it will use to analyze proposed Reliability Standards 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 meets or exceeds the criteria.

Designed for a Specific Goal

Proposed Reliability Standards must be designed to achieve a specified reliability goal.

The proposed Reliability Standard must address a reliability concern that falls within the requirements of Section 215 of the Federal Power Act. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection. Order No. 672 at P 321.

Further, 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

[1] FERC Order 672

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. NERC Reliability Principles[2]

The Purpose of BAL-002-WECC-2a Contingency Reserve is:

"To specify the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions."

Of the eight NERC Reliability Principles, this standard addresses Reliability Principle 1, which states:

"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."

Technically Sound

Proposed Reliability Standards must contain a technically sound method to achieve the goal.

The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the Electric Reliability Organization (ERO), in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons. Order No. 672 at P 324.

Standard Development

This proposed Reliability Standard was developed using the NERC and Western Electricity Coordinating Council (WECC) Reliability Standards Development Procedures (Procedures) approved by FERC and in effect at each point in the process. Among other things, these processes include drafting of the standard by a drafting team composed of subject matter experts (SME); biographies of those SMEs are provided with this filing.

These processes also include repeated public iterative comment/response cycles whereby comments are received from the industry, and responses to those comments are provided by the drafting team.

Technically Sound

On May 6, 2015, WECC received Standard Authorization Request (SAR) WECC-0115 BAL-002-WECC-2 Contingency Reserve, Request to Retire Requirement R2 (R2) requesting retirement of R2 and its

[2] https://www.nerc.com/files/Reliability_Principles.pdf

compliance elements.[3] The SAR stated that, on April 1, 2016, BAL-003-1.1 Frequency Response and Frequency Bias Settings, Requirement R1 would make R2 redundant.

To assess the potential risk of retiring R2, WECC conducted a NERC-approved field test from May 1, 2017, through April 30, 2018.[4] WECC required U.S. entities to provide data on the quantity of reserve carried during the field test period. Between October 18, 2018, and January 10, 2019, the WECC-0115 BAL-002-WECC-2a drafting team (DT) reviewed the test data and concluded that, if BAL-002-WECC-2a Requirement R2 is retired, it is unlikely to have an adverse effect on reliability.

To enable WECC to monitor the reliability effects of the field test, as a condition to participate in the field test, and to meet NERC's conditions in approving the field test, WECC required U.S. entities to provide the following information for any reportable Disturbance Control Standard (DCS) event:

- The date and time of the event;
- The required amount of Contingency Reserve at the time of the event;
- The actual amount of Operating Reserve—Spinning at the time of the event;
- The actual DSC performance.

Additionally, whether or not an incident was a reportable DCS event, for all instances of a loss of resources 700 MW or greater, entities were to report:

- The date and time of the event;
- The name of the resource(s);
- The total MW loss; and
- Any other relevant information.

Entities gave this information to WECC staff for each incident.

Applicability

Proposed Reliability Standards must be applicable to users, owners, and operators of the bulk power system, and not others.

The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others. Order No. 672 at P 322.

The Applicability section of BAL-002-WECC-2a, Contingency Reserve is as follows:

[3] The naming nomenclature changed during development from BAL-002-WECC-2, BAL-002-WECC-2a, and will change to BAL-002-WECC-3 if approved.

[4] NERC approved the field test in late March 2017 and WECC conducted it per NERC Standards Processes Manual, Section 6.2, Field Tests and Data Analysis for Validation of Requirement. A compliance waiver for R2 was granted beginning on May 1, 2017, and ending on May 1, 2019.

4. Applicability:

4.1 Balancing Authority

4.1.1. The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Reserve Sharing Group, in which case, the Reserve Sharing Group becomes the responsible entity.

4.2 Reserve Sharing Group

4.2.1. The Reserve Sharing Group when comprised of a Source Balancing Authority becomes the source Reserve Sharing Group

4.2.2. The Reserve Sharing Group when comprised of a Sink Balancing Authority becomes the sink Reserve Sharing Group.

Clear and Unambiguous

Proposed Reliability Standards must be clear and unambiguous as to what is required and who is required to comply.

The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability. Order No. 672 at P 325.

Understandable Consequence

Proposed Reliability Standards must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.

The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply. Order No. 672 at P 326.

This filing does not propose changes to the FERC-approved VSLs or VRFs. This filing proposes only a formatting change to the VRF.

Measurability for Compliance

Proposed Reliability Standards must identify a clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.

There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner. Order No. 672 at P 327.

This filing proposes retirement of BAL-002-WECC-2a, Requirement R2 with no further substantive changes to the existing FERC-approved standard.

Effective and Efficient

Proposed Reliability Standards should achieve a reliability goal effectively and efficiently - but does not necessarily have to reflect "best practices" without regard to implementation cost.

The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently. Order No. 672 at P 328.

During the two posting periods, no concerns were raised about implementation costs or regional infrastructure.

Lowest Common Denominator

Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect bulk power system reliability.

The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability. Order No. 672 at P 329.

The filing proposes retirement of BAL-002-WECC-2a, Requirement R2 because it is redundant to BAL-003-1.1 Frequency Response and Frequency Bias Settings, Requirement R1.

Costs

Proposed Reliability Standards may consider costs to implement for smaller entities but not at consequence of less than excellence in operating system reliability.

A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it. Order No. 672 at P 330.

During the development of the project, the industry raised no such concerns.

Continent-wide and Regional Variations

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 area or approach.

A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational 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. Order No. 672 at P 331.

In the Order 740 Remand at P4, the Commission states that:

"Reliability Standards that the ERO proposes to the Commission may include Reliability Standards that are proposed to the ERO by a Regional Entity… When the ERO reviews a regional Reliability Standard that would be applicable on an interconnection-wide basis and that has been proposed by a Regional Entity organized on an interconnection-wide basis, the ERO must rebuttably presume that the regional Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. In turn, the Commission must give "due weight" to the technical expertise of the ERO and of a Regional Entity organized on an interconnection-wide basis."

Further, regional entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard. NERC Rules of Procedure, Section 312, Regional Reliability Standards.

The filing requests retirement of BAL-002-WECC-2a Contingency Reserve, Requirement R2. If approved, the reliability-related tasks will default to the continent-wide requirement of BAL-003-1.1 Frequency Response and Frequency Bias Settings, Requirement R1.

No Undue Negative Effect

Proposed reliability standards should cause no undue negative effect on competition or restriction of the grid.

As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible

considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another. Order No. 672 at P 332

The DT does not foresee any negative effects on competition resulting from the proposed retirement.

During the development phase of this project, the industry raised no concerns about competition or restrictive use of the grid.

Implementation of New Requirements (Effective Date)

The implementation time for the proposed Reliability Standards must be reasonable.

In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability. Order No. 672 at P 333

Per the WECC Reliability Standards Development Procedures, Posting 1 (Attachment E4) of this project included an implementation plan for the proposed retirement. The Implementation Plan is included as Exhibit B of this filing.

When the DT published Posting 1 in October 2015, it proposed a retirement date coincident with the then-future effective date of BAL-003-1.1 Frequency Response and Frequency Bias Settings, Requirement R1. Because BAL-003-1.1, Requirement R1 is now effective, and while the reliability-related tasks of BAL-002-WECC-2a are addressed in BAL-003-1.1, Requirement R1, retirement of BAL-002-WECC-2a, Requirement R2 can be effective immediately upon receipt of regulatory approval.

Fair and Open Process

The Reliability Standard development process must be open and fair.

Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission. Order No. 672 at P 334

WECC followed the WECC Reliability Standards Development Procedures (Procedures) approved by FERC in effect at the time of each step in the process.

In accordance with the Procedures, all drafting team meetings are open to the public.

All drafting team meetings were announced via the WECC Standards Email List for the period prescribed in the Procedures. Notice of the meetings was provided to NERC and posted on the WECC Calendar along with meeting minutes.

All meetings were supported by a telephone conference bridge associated with an on-line internet visual capability allowing all participants to see the document(s) as they were being developed. Further, this team held an open-mic Standards Briefing prior to balloting affording the industry an additional opportunity to have its questions addressed.

This project was posted twice for public comment at WECC.

Comments and the associated responses are currently posted on the WECC website at the WECC-0115 project page on the Submitt and Review accordion.[5] Response to Comments forms were provided with this filing.

In addition to posting under the WECC Procedures, this project was also posted by NERC for 45-days in accordance with NERC's Rules of Procedure and NERC's internal business practices.

All comments received in that posting indicated WECC's development processes were: 1) open, 2) inclusive, 3) balanced, 4) transparent, and 5) provided due process.

Balanced with Other Vital Interests

Proposed Reliability Standards must balance with other vital public interests.

Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard. Order No. 672 at P 335

WECC is not aware of any other vital public interests. No such balancing concerns were raised or noted.

Consideration of Other Facts

Proposed Reliability Standards must consider any other relevant factors.

In considering whether a proposed Reliability Standard is just and reasonable, [FERC] will consider [several] general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed. Order No. 672 at P 323

[5] https://www.wecc.org/Standards/Pages/WECC-0115.aspx

WECC is not aware of any other general factors in need of consideration.

Exhibit E

Summary of Development History and
Complete Record of Development

Summary of Development History

The development record for proposed Regional Reliability Standard BAL-002-WECC-3 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team ("SDT") selected by the WECC Standards Committee ("WSC") to lead each project in accordance with Step 3 of the WECC Reliability Standards Development Procedures.[2] For this project, the SDT consisted of industry experts, all with a diverse set of experiences. A roster of the BAL-002-WECC-3 SDT members is included in **Exhibit F**.

II. Standard Development History

A. Standard Authorization Request Development

On May 6, 2015, WECC received Standard Authorization Request ("SAR") WECC-0115 to examine whether to retire BAL-002-WECC-2 Requirement R2.[3] After an affirmative review by the WECC Operating Committee, the SAR was approved by the WSC on June 23, 2015. Nominations for the drafting team were open from June 23, 2015 through July 31, 2015. The WSC approved the drafting team roster on August 12, 2015.

B. First Posting – Comment Period[4]

The project's first posting opened October 22, 2015, closing on December 8, 2015. After considering all comments received, on December 17, 2015, the SDT agreed to conduct a field test

---

1 Section 25(d)(2) of the Federal Power Act; 16 U.S.C. 824(d)(2) (2012).

2 The currently effective WECC RSDP is located at https://www.wecc.org/Reliability/WECC%20Reliability%20Standards%20Development%20Procedures%20-%20FERC%20Approved%20October%2027%202017%20-%202019%20Template.pdf.

3 The currently-effective version, BAL-002-WECC-2a, came into effect during the development of proposed BAL-002-WECC-3.

4 Posting materials for all postings are located on the WECC project page: https://www.wecc.org/Standards/Pages/WECC-0115.aspx. An implementation plan was filed as part of Posting 1.

to examine the ramifications of retiring Requirement R2.[5] On January 7, 2016, the SDT concluded a one-year data set would be sufficient to determine the impacts of retirement. The one-year data set began on May 1, 2017 and terminated on April 30, 2018.

C. Field Test

In late March 2017, NERC approved WECC's request for the field test. The test allowed WECC to waive compliance with BAL-002-WECC-2a Requirement 2 for all Reserve Sharing Groups ("RSG"), and all Balancing Authorities ("BA") that were not members of an RSG, that opted to participate in the field test. Participants were required to notify WECC of their intent to participate in the field test prior to receiving the waiver.

In late March 2017, NERC approved WECC's request for the field test.[6] The test allowed WECC to waive compliance with BAL-002-WECC-2a Requirement 2 for all Reserve Sharing Groups ("RSG") and all Balancing Authorities ("BA") which were not members of an RSG and who opted to participate in the field test. Participants were required to notify WECC of their intent to participate in the field test prior to receiving the waiver.

To enable WECC to monitor the reliability impacts of the field test, as a condition to participation in the field test, and to meet conditions specified by NERC in approving WECC's request for a field test, WECC required U.S. entities to provide the following information for any reportable Disturbance Control Standard ("DCS") event:

- The date and time of the event;
- The required amount of Contingency Reserves at the time of the event;
- The actual amount of Operating Reserves – Spinning at the time of the event; and

---

[5] "WECC-0115 Notice of Field Test" (2017), available at https://www.wecc.org/Reliability/WECC-0115%20Notice%20of%20Field%20Test.pdf.

- The actual DCS performance.

Additionally, whether or not an incident was a reportable DCS event, for all instances of a loss of resources 700 MW or greater, entities were to report:

- The date and time of the event;
- The name of the resource(s);
- The total MW loss; and
- Any other relevant information.

This information was provided to WECC staff for each incident.

Between October 18, 2018 and January 10, 2019, the SDT reviewed the test data and concluded that if Requirement R2 is retired, it is unlikely to have an adverse impact on reliability.

D. Second Posting – Comment Period

From January 18, 2019 through February 18, 2019, the SDT posted Posting 2 of the project (a technical white paper) in support of the retirement.[7] Posting 2 received three comments. After considering all comments, the SDT made editorial changes to its technical findings and provided additional footnotes to clarify data and language; however, the SDT did not change its conclusion that Requirement R2 should be retired. On February 28, 2019, the SDT agreed by majority vote to forward the project to the WSC with a request for ballot.

E. Ballot

On March 5, 2019, the WSC approved the project for ballot. Balloting was open from March 28, 2019 through April 11, 2019. It received 100% affirmative ballot in favor of retirement of Requirement R2, supported by an 89.5 percent quorum. On June 18, 2019, the WSC approved

7 "Field Test Results, WECC-0115 BAL-002-WECC-2a Request to Retire Requirement R2," Standard Drafting Team, March 5, 2019, Executive Summary, https://www.wecc.org/Reliability/WECC-0115%20Posting%202%20BAL-002-WECC-2%20Request%20to%20Retire%20R2%20-%20From%20Tech%20Editor.docx.

the ballot results and forwarded the project to the WECC Board of Directors ("Board") with a request for approval and subsequent disposition.

F. WECC Board of Directors Approval

On June 19, 2019, the WECC Board approved BAL-002-WECC-3 with the following resolution:

> Resolved, that the WECC Board of Directors (Board), acting upon the recommendation of the WECC Standards Committee (WSC) at the meeting of the Board on June 19, 2019, hereby approves the June 19, 2019 Board Voting Record 2 retirement of BAL-002-WECC-2a, Contingency Reserve, Requirement R2, the associated Measure M2, and the associated violation risk factor and violation severity levels, as presented and attached hereunto.[8]

G. NERC Comment Period and Board of Trustees Adoption

NERC posted proposed Regional Reliability Standard BAL-002-WECC-3 for a 45-day public comment period from June 20, 2019 through August 5, 2019. The NERC Board of Trustees adopted the proposed Regional Reliability Standard on August 15, 2019.

[8] Voting Record, WECC Board of Directors, June 19, 2019, Item 6. "Retire BAL-002-WECC-2a, Requirement," https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/2019-06-19%20Board%20Voting%20Record.pdf.

Complete Record of Development

Steven Rueckert
WECC Director of Standards
August 14, 2019

Ms. Nasheema Santos

NERC Reliability Standards Department

North American Electric Reliability Corporation

3353 Peachtree Rd. NE, North Tower—Suite 600

Atlanta, GA 30326

Subject: WECC-0115 BAL-002-WECC-3

Request to Retire Requirement R2

Dear Nasheema,

WECC is seeking approval from the NERC Board of Trustees, with subsequent disposition by the Federal Energy Regulatory Commission (FERC), to approve retirement of WECC Regional Reliability Standard, BAL-002-WECC-2a, Contingency Reserve, Requirement R2.

This project proposes retirement of R2 on the premise that R2 is redundant to BAL-003-1.1 Frequency Response and Frequency Bias Setting. The drafting team's conclusion is supported by technical justification (Exhibit C) premised on a NERC-approved field test.[1] Results of the field test indicate that adverse impact on reliability is unlikely.

When considering retirement of R2 it should be noted that BAL-003-1.1 represents a measurable performance calculated as an entity's known contribution to frequency response. By contrast, R2 has no technical foundation; rather, it represents a negotiated threshold established circa 1998 prior to mandatory standards.[2]

The request to retire R2 was approved by a WECC Ballot Pool with a 100 percent weighted approval.

Sincerely,

Steven Rueckert

WECC Director of Standards

[1] A NERC-approved field test was conducted from May 1, 2017, through April 30, 2018 examining the impact of retirement.

[2] Western System Coordinating Council, Reliability Criteria Agreement, 2. WSCC Criterion, (a.) Minimum Operating Reserve, (ii) Contingency reserve. Circa November 1998.

For documentation support please contact W. Shannon Black, at (503) 307-5782.

WECC-0115 BAL-002-WECC-3, Contingency Reserve[3] **Request to Retire Requirement R2**			
	QR	**BOT**	**Gov't Auth.***
Exhibit A – Final Standard - Clean			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Exhibit A - Final Standard - Clean			
Exhibit A1 - Final Standard – Redline			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Exhibit A1 - Final Standard – Redline			
Exhibit B – Final Implementation Plan			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Exhibit B – Final Implementation Plan			
Exhibit C – Final Technical Justification			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Exhibit C – Final Technical Justification			
Exhibit D - Order 672 Criteria			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Exhibit D – Order 672 Criteria			
Exhibit E - Summary of Development and WECC's Record of Development - NERC Provided Template			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve – Exhibit E - Summary of Development – NERC Provided			
Attachment E1 – WECC Standard Authorization Request			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Attachment E1 – WECC SAR			
Attachment E2 – Project Roadmap			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Attachment E2 – Project Roadmap			

[3] The naming nomenclature changed during development from BAL-002-WECC-2, BAL-002-WECC-2a, and will change to BAL-002-WECC-3 if approved.

Attachment E3 – NERC Submittal Request			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Attachment E3 – NERC Submittal Request			
Attachment E4 – Posting 1 Clean			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Attachment E4 – Posting 1 Clean			
Attachment E5 – Posting 1 Redline			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Attachment E5 – Posting 1 Redline – Not Used			
Attachment E6 – Posting 2 Clean			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Attachment E6 – Posting 2 Clean			
Attachment E7 – Posting 2 Redline			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Attachment E7 – Posting 2 Redline			
Attachment E8 – Posting 1 WECC Response to Comments			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Attachment E8 – Posting 1 Response to Comments			
Attachment E9 – Posting 2 WECC Response to Comments			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Attachment E9 – Posting 2 Response to Comments			
Attachment E10 – Minority Issues			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Attachment E10 – Minority Issues			
Attachment E11 – Ballot Pool Members			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Attachment E11 – Ballot Pool Members			
Attachment E12 – Ballot Pool Results			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Attachment E12 – Ballot Pool Results			
Attachment E13 – Posting 1 NERC Response to Comments			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Attachment E13 – NERC Posting 1 Response to Comments			

Attachment E14 – WECC Standards Committee Roster			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Attachment E14 – WECC Standards Committee Roster			
Exhibit F - WECC-0115 Drafting Team Roster			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Exhibit F – WECC Drafting Team Roster			
Exhibit G - VRF & VSL Justification			
File Name: WECC-0115 BAL-002-WECC-3 – Contingency Reserve —Exhibit G - VRF & VSL Justification			
Exhibit H - Issue Table and Mapping Document – Optional			
Not Used			
Exhibit I - Guidance Document - Optional			
Not Used			
Exhibit J - Additional Supporting Documentation – Optional			
Not Used			
The above documents have been provided to NERC in MS Word format.			

Electric Reliability and Security for the West

Attachment E1
WECC Standard Authorization Request
WECC-0115 BAL-002-WECC-3
Contingency Reserve
Request to Retire R2

Introduction

This Standard Authorization Request (SAR) was assigned WECC Tracking Number WECC-0115.

On May 6, 2015, WECC received Standard Authorization Request (SAR) WECC-0115 to examine whether to retire BAL-002-WECC-2 Requirement R2.[1] After an affirmative review by the WECC Operating Committee, the SAR was approved by the WECC Standards Committee (WSC) on June 23, 2015. Nominations for the drafting team were received from June 23, 2015 through July 31, 2015. The WSC approved the drafting team roster on August 12, 2015.[2]

Requester Information

Provide your contact information and your alternate's contact information:

Primary contact

- First name: James
- Last name: Wells
- Email: James.wells@ladwp.com
- Phone: (818) 77-6701
- Organization name: Los Angeles Department of Water and Power

Alternate

- First name: W. Shannon
- Last name: Black
- Email: sblack@wecc.org
- Phone: (503) 307-5782

[1] The naming nomenclature changed during development from BAL-002-WECC-2, BAL-002-WECC-2a, and will change to BAL-002-WECC-3 if approved.

[2] This document was added to the WECC Intranet on August 12, 2019, after being updated to WECC's newest document templates. The SAR in its original format is available upon request from the WECC Standards Department.

Type of Request

Specify the type of request: (Select one)

- Request to Modify a Regional Reliability Standard (RRS)

Create, Modify, Retire, or Review a Document

Provide information for your request to create, modify, retire, or review the document.

Pick from the dropdown provided in the online form.

Requested Action (Select one)

- Request to Retire BAL-002-WECC-2, Requirement R2[3]

Document Type (Select one)

- Regional Reliability Standard

Issue

Specify what industry problem this request is trying to resolve.

BAL-003-1, Frequency Response and Frequency Bias Setting

On January 16, 2014, FERC approved BAL-003-1, Frequency Response and Frequency Bias Setting, Requirement R1, with an effective date of April 1, 2016. The text of BAL-003-1, Requirement R1 states:

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation.

BAL-003-1, Requirement R1 is an annual measure requiring a full 12 months of performance measurements, collected through Frequency Response Forms (FRS) 1 and 2, summarizing frequency response settings for participating Balancing Authorities (BA), for a period of December through November of the following year, in accordance with BAL-003-1 and its Attachment A.

[3] On January 24, 2017, the Federal Energy Regulatory Commission (FERC) approved interpretation of BAL-002-WECC-2, which clarified the types of resources that may be used to satisfy Contingency Reserve. The standard's name was changed to BAL-002-WECC-2a.

BAL-003-1, Requirement R1 will become enforceable for frequency events occurring December 2016 through November 2017. Frequency Response Measures for compliance with BAL-003-1, Requirement R1 will be submitted no later than March 7, 2018.

Compliance will be judged against Balancing Authority Frequency Response Obligations (BA FRO) calculated annually based on the Interconnection Frequency Response Obligations (IFROs) calculated and approved by the NERC Operating Committee.

With the implementation of BAL-003-1, standards now exist that define requirements for acceptable Frequency Response from the BA to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. Additionally, [BAL-003-1] provides consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

BAL-002-WECC-2, Contingency Reserve

BAL-002-WECC-2, Requirement R2 becomes redundant as of the April 1, 2016, effective date of BAL-003-1. Further, there is no technical support or reason for retaining BAL-002-WECC-2, Requirement R2 once BAL-003-1 becomes effective.

Leaving BAL-002-WECC-2 in place would require the BA or Reserve Sharing Group to carry additional spinning reserve with the intended purpose of supporting the frequency of the Western Interconnection. The 50 percent spinning reserve requirement has no measurable performance metric with respect to interconnection frequency support.

Proposed Remedy

Specify how this request will address the issue you stated above.

- Retire BAL-002-WECC-2, Contingency Reserve, Requirement R2.

Purpose:

The purpose of this Standard Authorization Request (SAR) is to delete BAL-002-WECC-2, Contingency Reserve, Requirement R2 and Measurement M2. The modification should be coincident with implementation of BAL-003-1, Requirement R1 that specifies BA frequency response obligation and performance measurement. The text of BAL-002-WECC-2, Requirement R2 is as follows:

R2. Each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve identified in Requirement R1, as Operating Reserve – Spinning that meets both of the following reserve characteristics. [Violation Risk Factor: High] [Time Horizon: Real-time operations]

2.1 Reserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system;

2.2 Reserve that is capable of fully responding within ten minutes.

Removing BAL-002-WECC- 2, Requirement R2 does not change the amount of a BA's contingency reserve requirement specified in BAL-002-WECC-2, Requirement R1.

Operating Reserve will only require reserve fully capable of responding within ten minutes to support the Disturbance Control Standard (DCS).

Applicable Entities

- Balancing Authority
- Reserve Sharing Groups
- Frequency Response Sharing Group

Detailed Description

See above.

Affected Reliability Principles

Which of the NERC Reliability Principles is most affected by this request?

- **Reliability Principle 1** — Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Reference Uploads

Specify the document title, document number, and affected section regarding the request.

- BAL-002-WECC-2, Contingency Reserve, Requirement R2

Additional Comments

Please reference or upload any affected standards, regional business practices, criteria, policies, white papers, technical reports, or other relevant documents. If this request is based on a conflict of law, please include a copy of—or accessible reference to—the specific law or regulatory mandate in conflict.

- None

Electric Reliability and Security for the West

Attachment E2

Project Roadmap

WECC-0115 BAL-002-WECC-3

Contingency Reserve

Request to Retire R2

Description of Current Draft

Per the WECC Reliability Standards Development Procedures (Procedures) this is a request to retire Requirement R2 of BAL-002-WECC-2, Contingency Reserve.

Completed Actions	Date Completed
WECC-0115 Standard Authorization Request (SAR)—Request to Retire Requirement R2 of BAL-002-WECC-2 received and deemed complete	May 6, 2015
WECC Joint Guidance Committee approved the SAR approach	May 27, 2015
WECC Operating Committee approved the SAR approach	June 9, 2015
WECC Standards Committee (WSC) approved the SAR	June 23, 2015
Notice of Solicitation—WECC-0115 Drafting Team	June 29, 2015
Notice of Solicitation—WECC-0115 Drafting Team—Extended	July 14, 2015
Nominations closed	July 31, 2015
WSC approved the team roster	August 12, 2015
Drafting Team (DT) meeting	October 1, 2015
DT Meeting	October 22, 2015
Posting 1—opened	October 22, 2015
Posting 1—closed	December 8, 2015
DT meeting[1]	December 17, 2015
DT meeting—DT approved field test parameters (Exhibit C)	January 7, 2016
WSC updated	September 6, 2016
Field test approval under development by WECC and NERC. The NERC vice president of Standards and Compliance had to approve the test.	
NERC approved WECC request for field test to examine retirement of R2	March 2017
Notice of field test dispatched	April 11, 2017
Field test begins	May 1, 2017

[1] The DT agreed by majority vote to pursue a field trial to determine the potential effects of retiring BAL-002-WECC-2, Requirement R2.

Field test ends	April 30, 2018
DT meeting[2]	October 18, 2018
DT meeting	November 1, 2018
DT meeting	November 29, 2018
DT meeting	January 10, 2019
Posting 2—open	January 18, 2019
Posting 2—closed	February 18, 2019
DT meeting	February 21, 2019
DT meeting	February 28, 2019
Field test ends (originally proposed end date)	March 30, 2019
Initial compliance waiver ends	May 1, 2019
WSC approved for ballot	March 5, 2019
Notice of Ballot Pool forming / Notice of Ballot	March 7, 2019
Ballot Pool opened	March 11, 2019
Notice of Standards Briefing	March 12, 2019
Ballot Pool closed	March 26, 2019
Standards Briefing	March 27, 2019
Ballot opened	March 28, 2019
Ballot closed	April 11, 2019
WSC approves sending to WECC Board of Directors (Board)	June 18, 2019
Board approves for NERC/FERC disposition	June 19, 2019
NERC 45-day comment open	June 20, 2019
NERC 45-day comment closed	August 5, 2019
NERC Board of Trustees approved	August 15, 2019
Filed with FERC	Pending

[2] Analysis of the field test data indicated that sufficient reserves were being carried even though a compliance waiver was in effect. The threshold conclusion was that retirement of Requirement R2 would have no detrimental effect on the grid.

Regional Reliability Standard Submittal Request
Attachment E3

Region:	**Western Electricity Coordinating Council**
Regional Standard Number:	**BAL-002-WECC-3**[1]
Regional Standard Title:	**Contingency Reserve**
Date Submitted:	**August 30, 2019**
Regional Contact Name:	**Steven Rueckert**
Regional Contact Title:	**Director of Standards**
Regional Contact Telephone Number:	**(801) 883-6878**

Request (check all that apply):

- ☒ Retirement of WECC Regional Reliability Standard Requirement BAL-002-WECC-2a (R2)
- ☐ Interpret an existing standard
- ☐ Approval of a new standard
- ☒ Revision of an existing standard: BAL-002-WECC-2a
- ☐ Withdrawal of an existing standard
- ☐ Urgent action

Has this action been approved by your Board of Directors:

- ☒ Yes
- ☐ No

(If no please indicate date standard action is expected along with the current status (e.g., third comment period with anticipated board approval on mm/dd/year)):

On June 19, 2019, the WECC Board of Directors (Board) approved BAL-002-WECC-3 with the following resolution:

[1] The naming nomenclature changed during development from BAL-002-WECC-2, BAL-002-WECC-2a, and will change to BAL-002-WECC-3 if approved.

"Resolved, that the WECC Board of Directors (Board), acting upon the recommendation of the WECC Standards Committee (WSC) at the meeting of the Board on June 19, 2019, hereby approves the retirement of BAL-002-WECC-2a, Contingency Reserve, Requirement R2, the associated Measure M2, and the associated violation risk factor and violation severity levels, as presented and attached hereunto."	
[Note: The purpose of the remaining questions is to provide NERC with the information needed to file the regional standard(s) with FERC. The information provided may to a large degree be used verbatim. It is extremely important for the entity submitting this form to provide sufficient detail that clearly delineates the scope and justification of the request.]	
Concise statement of the basis and purpose (scope) of request:	This project proposes retirement of BAL-002-WECC-3 Contingency Reserve, Requirement R2 on the premise that R2 is redundant to BAL-003-1.1 Frequency Response and Frequency Bias Setting.
Concise statement of the justification of the request:	The project drafting team recommendation to retire Requirement R2 is supported by technical justification (Exhibit C) premised on a NERC-approved field test. Results of the field test indicate that adverse impact on reliability is unlikely. When considering retirement of Requirement R2 it should be noted that BAL-003-1.1 Frequency Response and Frequency Bias Setting represents a measurable performance calculated as an entity's known contribution to frequency response. By contrast, BAL-002-WECC-2a, Requirement R2 has no technical foundation; rather, it represents a negotiated threshold established circa 1998 prior to mandatory standards.

Electric Reliability and Security for the West

Attachment E4

Posting 1

WECC-0115 BAL-002-WECC-3, Contingency Reserve

Request to Retire R2

Memo

Date: October 23, 2019

To: WECC Standards Email List

Subject: WECC-0115 BAL-002-WECC-2—Contingency Reserve Request to Retire Requirement R2

Question for Survey[1]

Do you agree that WECC Regional Standard BAL-002-WECC-2, Contingency Reserve, Requirement R2 should be retired as of the effective date of NERC Standard BAL-003-1[2] (BAL-003), Frequency Response and Frequency Bias Setting, Requirement R1?

If you answered no to the above question, please explain your answer.

Recommendation

The WECC-0115, BAL Drafting Team is recommending retirement of BAL-002-WECC-2, Contingency Reserve, Requirement R2 as of the effective date of BAL-003-1, Frequency Response and Frequency Bias Setting, Requirement R1.

BAL Requirement R1 is not impacted by this project.

Language for Retirement

The language proposed for retirement is as follows:

R2. Each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve identified in Requirement R1, as

[1] This document has been updated to reflect the most recent WECC template. The document in its original format is located on the WECC-0115 project page: https://www.wecc.org/Reliability/WECC-0115%20Posting%201%20BAL-002-WECC-2%20Request%20to%20Retire%20R2%20-%2010-23-2015%20through%2012-8-2015.docx

[2] BAL-003-1, Frequency Response and Frequency Bias Setting is approved by the Federal Energy Regulatory Commission (March 24, 2014) and has an enforcement date of April 1, 2016.

Operating Reserve – Spinning that meets both of the following reserve characteristics. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

2.1 Reserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system;

2.2 Reserve that is capable of fully responding within ten minutes.

Background

On November 21, 2013 in Order 789, the Federal Energy Regulatory Commission (FERC) approved WECC Regional Standard BAL-002-WECC-2 (the WECC BAL) with an Effective Date of October 1, 2014.

The WECC BAL applies to Balancing Authorities and Reserve Sharing Groups in the WECC Region and is meant to specify the quantity (Requirement R1) and types (Requirement R2) of contingency reserve required to ensure reliability under normal and disturbance conditions.

Requirement R1 requires the applicable entity to "maintain a minimum amount of Contingency Reserve" whereas Requirement R2 requires that "at least half of [an entity's] minimum amount of Contingency Reserve identified in Requirement R1, as Operating Reserve – Spinning [must meet specific] reserve characteristics."

To qualify as Operating Reserve—Spinning,[3] the reserve maintained in accordance with Requirement R2 must be:

- Generation synchronized to the system and fully available to serve load [automatically] within the Disturbance Recovery Period following the contingency event; or
- Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

Intent of BAL-002-WECC-2, Requirement R2

The intent of Requirement R2 was to delineate "how" a reserve type must respond without creating a definitive list of the types of reserve that might be used to meet the requirement. This intent was made clear in the WECC-0115, BAL Drafting Team's (DT) Guidance Document that included Frequently Asked Questions (FAQ) regarding the development of the WECC BAL. There the drafting team noted that in the absence of a frequency response standard the original WECC Minimum Operating Reliability Criteria[4] (MORC) needed to have an element that was capable of arresting a frequency excursion and supporting frequency during the recovery period.

[3] See the definition of Operating Reserve contained in the NERC Glossary of Terms Used in NERC Reliability Standards.

[4] WECC Minimum Operating Reliability Criteria, April 6, 2005 (MORC).

The drafting team noted at FAQ 11[5]:

> When the drafting team incorporated the FERC mandated [glossary] terms, it determined that the definition for Contingency Reserve – Spinning did not require that it be automatically responsive to frequency. To fill that void, the drafting team included in the current version [of the WECC BAL] the historical WECC requirement that spinning reserve must be automatically responsive proportionally to frequency deviations. Parenthetically, this approach should also assuage some concerns that the frequency component of the earlier Purpose statement is no longer offered.

The intent of Requirement R2 was to ensure that the right type of reserve was available specifically to address frequency response.

Subsequent to the approval of the WECC BAL, FERC has approved BAL-003 specifically addressing frequency response. The Purpose of BAL-003 is "to require sufficient Frequency Response" from Balancing Authorities and Frequency Response Sharing Groups as specified in the Applicability section of BAL-003. The frequency response component of the WECC BAL's Requirement R2 is now covered in BAL-003; the specific content of BAL-003 directly addresses the indirect and general content of the WECC BAL, and the historical[6] premise for the WECC BAL no longer reflects the present-day granular visibility from one Balancing Authority to another; therefore, the language of the WECC BAL's Requirement R2 should be retired. The reliability-related substance of the WECC BAL is provided for by the frequency response performance components of BAL-003.

Requirement R2—Main Body

BAL-003 is a superior standard to the WECC BAL because BAL-003 is a result-based standard that achieves the WECC BAL's Requirement R2 reliability goal by requiring the applicable entity to perform in accordance with a specified performance metric. By contrast, the WECC BAL has no stated performance requirement or compliance metric associated with requirement2 and is measured solely on documentation presented after-the-fact.

Retention of both WECC BAL Requirement R2 as well as BAL-003 Requirement R1 could lead to confusion and the needless procurement of additional reserve, thereby increasing costs without benefit. The WECC BAL's Requirement R2 specifies procurement of Contingency Reserve, at least one half of

[5] WECC-00083 BAL-002-WECC-1 (and 2), Guidance Document, presented to the industry in Posting 5 of the BAL project and also provided as Attachment S as part of WECC's filing to NERC/FERC that sought approval of the BAL.

[6] The language of the existing BAL is premised on the MORC that was originally drafted to address a 1970s-era paradigm in which visibility, data exchange, and understanding of other Balancing Areas was minimal. During that pre-standards era, frequency deviation was largely addressed by manual and analogue intervention, and interaction between control areas was based on the premise of mutual cooperation not supported by regulatory mandates.

which must be comprised of Operating Reserve—Spinning. The intent of Requirement R2 is to have reserve resources that both arrest and support frequency. BAL-003 meets the same reliability-related goal without specifying the type of resource from which the outcome can be produced. If kept in tandem the result could be that an entity procures a specific amount and type of reserve to meet the WECC BAL and also procures a different and possibly superior resource to meet the separate requirement of BAL-003. As a result, retirement of R2 will not create a reliability gap because BAL-003, Requirement R1 meets the same need. Further, retirement of R2 could actually lower the cost of reliability by eliminating the potential for redundant reserve procurement.[7]

As illustrated in BAL-003, "how" frequency support is achieved need not be prescribed like it is in the WECC BAL. Under the WECC BAL, the response must result from Operating Reserve – Spinning provided in a specific quantity. As pointed out in the supporting documentation for BAL-003, the same reliability-related goal can be met by any of the following: 1) Regulation services, 2) contract services, 3) tariff arrangements, or 4) generator/load agreements. Since the goal of BAL-003, Requirement R1 is to meet a Frequency Response Measure, by definition, Frequency Response can be obtained by either a system or more discrete sub-elements of the system. There is no need to prescribe the specific stockpile of resources as has been done in the WECC BAL's Requirement R2. This position is in accord with that of the BAL-003 drafting team.[8]

Section 2.1

Requirement R2, Section 2.1 can be retired because it is already addressed in BAL-003. Requirement R2.1 requires use of resources that are immediately and automatically responsive to frequency deviations through the action of a governor or other control system. BAL-003, without specifying the stockpile of resources, requires the applicable entity to meet a specific Frequency Response Measure equal to or more negative than its Frequency Response Obligation.

Section 2.2

Requirement R2, Section 2.2 can be retired because it is already addressed in Requirement R2, Section 2.1. Section 2.1 requires the applicable entity to carry reserve "that is immediately and automatically responsive to frequency." Section 2.2 requires the applicable entity to carry reserves "capable of fully responding within ten minutes." Section 2.1's immediate response-time renders the Section 2.2 ten-

[7] A good contract for the acquisition of Frequency Response will provide "a method to evaluate the least cost mix of resources necessary to provide the minimum required Frequency Response for maintain reliability. Finally, it will provide the least complex method of evaluation considering the complexity and efficient of the acquisition process." NERC Frequency Response Standard Background Document, Frequency Response Costs – Supply Side, page 20, November 2012.

[8] NERC Frequency Response Standard Background Document, Methods of Obtaining Frequency Response, page 37, November 2012.

minute response time moot. The drafting team notes the language is a carryover from the MORC and should be updated through retirement.

Implementation Plan

In accordance with the Reliability Standards Development Procedures (Procedures), Step 5- Post for Comment, "[a]n implementation plan shall be included in at least one iterative posting during the development of the [Regional Reliability Standard] and shall be a part of the final record for consideration prior to ballot."

On May 6, 2015, WECC accepted a Standards Authorization Request (SAR) requesting retirement of BAL-002-WECC-02, Contingency Reserve, Requirement R2.

The SAR is located at the Standards Authorization Request accordion of the WECC-0115 BAL-002-WECC-2, Request to Retire Requirement R2 project page.

Procedural approvals are required from:

- The WECC Standards Committee
- The Ballot Pool
- The WECC Board of Directors
- The NERC Board of Trustees
- The Federal Energy Regulation Commission
- Other regulatory bodies as applicable

Proposed Effective Date

The WECC-0115, BAL Drafting Team is recommending retirement of BAL-002-WECC-2, Contingency Reserve, Requirement R2 as of the effective date of BAL-003, Frequency Response and Frequency Bias Setting, Requirement R1.

Justification of Effective Date

The reliability-related substance of WECC BAL's Requirement R2 is contained in BAL-003. Because the reliability task is addressed in BAL-003, once BAL-003 Requirement R1 is effective there will no longer be a need for WECC BAL Requirement R2.

Impact on Other Standards

As to other existing and proposed standards, the drafting team notes that some confusion may arise as to how the retirement of WECC BAL Requirement R2 may interplay with the existing BAL-002-1, Disturbance Control Performance standard. BAL-002-1, Requirement R2.3 requires the applicable entity (the Regional Reliability Organization "or" the Reserve Sharing group) to "specify its Contingency Reserve policies, including…(R2.3.)…the permissible mix of Operating Reserve—Spinning and

Operating Reserve—Supplemental that may be included in Contingency Reserve." Arguably, BAL-002-WECC-2, Requirement R2 meets this requirement.

The drafting team disagrees that retention of BAL-002-WECC-2, Requirement R2 is the only means of compliance with BAL-002-1. At a high level, since BAL-002-1 has no Measure for the associated Requirement R2, how compliance might be met is ethereal. Further, since the only Measure provided requires that the Balancing Authority "or" the Reserve Sharing group "shall calculate and report compliance with the Disturbance Control Standard" there is a decided disconnect between the required performance (have a policy) and the required Measure (perform a calculation).

Consideration of Early Compliance

Retirement of WECC BAL Requirement R2 should not take place until the industry mandate to comply with BAL-003-1 goes into place. Early retirement could create a reliability gap resulting from insufficient reserves.

Not Used

Posting 1 asks only whether BAL-002-WECC-2a Contingency Reserve, Requirement R2 should be deleted. No other language changes were proposed.

Attachment E6

Posting 2—Clean

WECC-0115 BAL-002-WECC-3

Contingency Reserve

Request to Retire R2

WECC

Field Test Results
WECC-0115 BAL-002-WECC-2a
Request to Retire Requirement R2

Standard Drafting Team

March 5, 2019

Executive Summary

After doing a field test from May 1, 2017, through April 30, 2018, the WECC-0115 BAL-002-WECC-2a, Contingency Reserve, Request to Retire Requirement R2 Drafting Team (DT) concluded that if Requirement R2 is retired, it is unlikely to have an adverse impact on reliability.

On May 6, 2015, WECC received Standard Authorization Request (SAR) WECC -0115 BAL-002-WECC -2a Contingency Reserve, Request to Retire Requirement R2 (R2) requesting retirement of R2 and its compliance elements. The SAR stated that on April 1, 2016, R2 would become redundant to BAL-003-1.1 Frequency Response and Frequency Bias Settings, Requirement R1.

From May 1, 2017, through April 30, 2018, WECC did a NERC-approved field test to find out the impact on reliability if R2 was retired.[1] A compliance waiver for R2 was granted beginning on May 1, 2017 and ending on May 1, 2019.

WECC required U.S. entities to provide data on the quantity of reserve carried during the field test period. This was done to enable WECC to see the impacts of the field test, as a condition to take part in the field test, and to meet conditions from NERC in approving WECC's request for a field test. The data showed no adverse impact to reliability if R2 is retired.

Project WECC-0115 will not be balloted until this report is presented for review to the WECC Ballot Pool and the requirements of the NERC Rules of Procedure, 6.3 Communication and Coordination for All Types of Field Tests and Data Analyses have been met by NERC.

[1] The field test was approved by NERC in late March 2017 and conducted per NERC Standards Processes Manual, Section 6.2, Field Tests and Data Analysis for Validation of Requirement.

Table of Contents

Introduction **4**

Field Test Description **4**

Data Source and Description 4

Field Test Analysis and Results **5**

Data Description 6

DCS Event Field Test Data ..... **Error! Bookmark not defined.**

Figures

Table 1—DCS Event Field Test Data 6

Figure 1—Table 2.1 from NERC 2018 State of Reliability Report, June 2018 10

Figure 2—A to B IFRM 11

Figure 3—A to C IFRM 12

Figure 4—Cn to C Ratio 13

Figure 5—Table 2.2 from NERC 2018 Frequency Response Annual Analysis, November 2018 14

Figure 6—Cn to UFLS margin 14

Introduction

On May 6, 2015, WECC received Standard Authorization Request (SAR) WECC-0115 BAL-002-WECC-2a, Contingency Reserve requesting retirement of Requirement R2 (R2). The SAR was deemed complete the same day. The SAR asserted that, on April 1, 2016, Requirement R2 would become redundant to BAL-003-1.1, Requirement R1, Frequency Response and Frequency Bias Setting.

On June 23, 2015, the WECC Standards Committee (WSC) approved the SAR after vetting by the WECC Operating Committee Steering Committee (OC; June 9, 2015) and the Joint Guidance Committee (JGC; May 27, 2015).

From October 22 through December 8, 2015, the project was posted once for comment, during which stakeholders were asked a question:

> Do you agree that WECC Regional Standard BAL-002-WECC-2,[2] Contingency Reserve, Requirement R2 should be retired as of the effective date of NERC Standard BAL-003-1[3] (BAL-003), Frequency Response and Frequency Bias Setting, Requirement R1?

Three entities responded to the posting and were in favor of retirement.[4] After discussion with staff, the DT and WECC staff[5] agreed that a field test should be done to gauge the impact of retiring R2.

A NERC-approved field test was done from May 1, 2017, through April 30, 2018. The field test data is the foundation of this paper and was posted for comment as Posting 2 of this project. Posting 2 received three comments, one for retirement and two suggesting caution.

Field Test Description

Data Source and Description

The field test data was requested from each Balancing Authority (BA) and each Reserve Sharing Group (RSG) subject to R2. Data was received by WECC through an online WECC portal.

The data request included the following information:

[2] During this project, the BAL-002-WECC-2 designation changed to BAL-002-WECC-2a on January 24, 2017, in FERC Docket No. RD17-3-000. The BAL-003-1 designation changed to BAL-003-1.1 on November 13, 2015, in FERC Docket RD15-6-000.

[3] BAL-003-1, Frequency Response and Frequency Bias Setting is approved by the FERC on March 24, 2014 and has an enforcement date of April 1, 2016.

[4] Xcel Energy, Bonneville Power Administration, and WECC.

[5] Steven Rueckert, WECC Director of Standards, and Phil O'Donnell, WECC Manager, Operations and Planning Audits and Investigations.

1. For any reportable Disturbance Control Standard (DCS) event, the date and time of the event, the required amount of Contingency Reserves at the time of the event, the actual amount of Operating Reserves-Spinning at the time of the event, and the actual DCS performance.[6]
2. For all instances of a loss of resources 700 MW or greater, whether it is a reportable DCS event or not, the date and time of the event, the name of the resource(s), and the total MW loss.

Objective

The field test was designed to determine whether retirement of R2 would have any adverse impact on grid reliability. The test examined the impact on Disturbance Control Standard (DCS[7]) performance and frequency response in the Western Interconnection.

Overview

The first metric, DCS performance, monitored the performance of each RSG and each BA that was not a member of an RSG, for every reportable DCS event, to see whether any were unable to meet the DCS recovery period for a DCS event. More information was requested from the participants to calculate the ratio for required contingency reserve to Operating Reserve-Spinning for each qualified event.

The second metric watched system performance for any loss of resources greater than 700 MW and for any adverse impact on frequency response.[8] Data for this metric was collected using the same information used by NERC to collect information to perform analysis on interconnection frequency response analysis for the NERC State of Reliability and Frequency Response Annual Analysis reports.

Field Test Analysis and Results

BAL-002-WECC-2a, Requirement R2 was intended to do two things: 1) to aid in frequency recovery (through governor action) for large generation loss events across the Western Interconnection, and 2) to provide a part of the Contingency Reserves (on-line generation minus 10-minute response) for generation trip events within the BA or RSG, if the party is an RSG member. With the implementation of new standards and a change of generation resources in the Western Interconnection, the SAR was based on the presumptions that BAL-002-WECC-2a, Requirement R2 became redundant as of the April

[6] During the field test, only the DCS responsible entity was asked to provide data during DCS events. Entities that did not have a reportable DCS event were not requested to provide data.

[7] "The reliability standard that sets the time limit following a Disturbance within which a BA must return its Area Control Error to within a specified range." NERC Glossary of Terms Used in Reliability Standards (Glossary).

[8] The DT noted that the WECC Interconnection Frequency Response Obligation (IFRO) is roughly -840 MW per 0.1 HZ. The 700-MW loss was chosen as a more conservative number than the IFRO and represents a value large enough to cause a significant frequency excursion. For an example, see Frequency Response Analysis Tool, Dmitry Kosterev, Bonneville Power Administration, 2014. https://www.wecc.org/Reliability/Frequency%20Response%20Analysis%20-%20Dmitry%20Kosterev.pdf

1, 2016, effective date of BAL-003-1.1 Frequency Response and Frequency Bias Setting, and that, with its retirement, neither interconnection frequency performance metrics nor DCS performance would degrade.

With the implementation of BAL-003-01.1, frequency response became measurable, and the field test gave entities a compliance waiver for WECC BAL-002-WECC-2a Requirement R2, thus splitting DCS and frequency response. Entities were responsible for ensuring both reliability performance metrics were met. On that basis, the data captured from the field test was used with interconnection frequency response performance data to assess any impact to individual DCS performance as well as overall interconnection frequency performance.

Data Description

Data from the field test covered 66 DCS events. During each of those events, entities provided data to help assess DCS performance. This data included Contingency Reserve Obligation, Required Spin (assuming no compliance waiver), Actual Spin, and whether Area Control Error recovery was met to successfully pass the DCS event. See Table 1 for the data set collected.

Table 1—DCS Event Field Test Data

Entity #	Reported MW Loss	DCS Event	Contingency (Cont) Reserve Obligation	Required Spin	Actual Spin	Pass(x)	Cont/Spin (Pre-Contingency Value)
Entity 3	530	Yes	585	293	878	x	150.09%
Entity 3	480	Yes	585	293	1165	x	199.15%
Entity 5	341	Yes	2624	1312	5595	x	213.22%
Entity 5	309	Yes	2528	1264	4095	x	161.99%
Entity 5	310	Yes	2830	1415	4428	x	156.47%
Entity 5	294	Yes	2992	1496	4010	x	134.02%
Entity 5	480	Yes	2349	1174.5	4360	x	185.61%
Entity 5	375	Yes	3068	1534	4986	x	162.52%
Entity 5	393	Yes	3106	1553	3989	x	128.43%
Entity 5	587	Yes	2373	1187	4483	x	188.92%
Entity 5	628	Yes	3124	1562	4201	x	134.48%
Entity 5	388	Yes	3211	1606	4217	x	131.33%
Entity 5	838	Yes	2988	1494	4223	x	141.33%
Entity 5	353	Yes	3234	1617	4658	x	144.03%
Entity 2	655	Yes	656	328	552	x	84.26%
Entity 5	356	Yes	3646	1823	5956	x	163.36%
Entity 5	619	Yes	3732	1866	6193	x	165.94%
Entity 2	430	Yes	468	234	417	x	89.11%
Entity 5	513	Yes	3514	1757	6063	x	172.54%
Entity 5	519	Yes	2823	1412	6001	x	212.58%
Entity 5	748	Yes	3688	1844	6271	x	170.04%

Entity #	Reported MW Loss	DCS Event	Contingency (Cont) Reserve Obligation	Required Spin	Actual Spin	Pass(x)	Cont/Spin (Pre-Contingency Value)
Entity 5	630	Yes	3024	1512	6680	x	220.90%
Entity 2	**442**	**Yes**	**538**	**269**	**231**	**x**	**42.97%**
Entity 5	506	Yes	3610	1805	6703	x	185.68%
Entity 5	760	Yes	3742	1871	6133	x	163.90%
Entity 5	522	Yes	3612	1806	5698	x	157.75%
Entity 5	1061	Yes	3791	1896	6799	x	179.35%
Entity 5	411	Yes	2964	1482	5358	x	180.77%
Entity 5	1882	Yes	2497	1249	4952	x	198.32%
Entity 5	486	Yes	3536	1768	5855	x	165.58%
Entity 5	475	Yes	3422	1711	6647	x	194.24%
Entity 5	723	Yes	3006	1503	8401	x	279.47%
Entity 5	796	Yes	3293	1647	5844	x	177.47%
Entity 5	492	Yes	3174	1587	5111	x	161.03%
Entity 5	460	Yes	5129	2565	9318	x	181.67%
Entity 5	398	Yes	5614	2807	11920	x	212.33%
Entity 5	1150	Yes	5231	2616	13142	x	251.23%
Entity 5	1699	Yes	6028	3014	9288	x	154.08%
Entity 5	786	Yes	5874	2937	9350	x	159.18%
Entity 5	479	Yes	5155	2578	14798	x	287.06%
Entity 3	538	Yes	585	293	1329	x	227.23%
Entity 5	714	Yes	5869	2935	11056	x	188.38%
Entity 5	656	Yes	6090	3045	14291	x	234.66%
Entity 5	760	Yes	5517	2759	8679	x	157.31%
Entity 3	790	Yes	790	395	1607	x	203.42%
Entity 2	496	Yes	573	286	379	x	66.15%
Entity 5	1046	Yes	8090	4045	12613	x	155.91%
Entity 5	493	Yes	7099	3550	12659	x	178.32%
Entity 5	651	Yes	3351	1676	5962	x	177.92%
Entity 1	388	Yes	1040	520	979	x	94.13%
Entity 4	851	Yes	2181	1091	1091	x	50.02%
Entity 1	970	Yes	1037	519	1151	x	110.99%
Entity 4	1059	Yes	1175	588	600	x	51.06%
Entity 3	582	Yes	790	395	924	x	116.96%
Entity 2	**800**	**Yes**	**565**	**283**	**234**	**x**	**41.44%**
Entity 1	471	Yes	1040	520	1359	x	130.67%
Entity 1	699	Yes	1041	521	1426	x	136.98%
Entity 4	**817**	**Yes**	**1543**	**772**	**768**	**x**	**49.77%**
Entity 5	1026	Yes	2832	1416	6038	x	213.21%
Entity 5	850	Yes	2741	1371	6543	x	238.71%

Entity #	Reported MW Loss	DCS Event	Contingency (Cont) Reserve Obligation	Required Spin	Actual Spin	Pass(x)	Cont/Spin (Pre-Contingency Value)
Entity 5	660	Yes	2691	1346	5911	x	219.66%
Entity 1	500	Yes	1040	520	1589	x	152.79%
Entity 5	506	Yes	3206	1603	5893	x	183.81%
Entity 5	707	Yes	3056	1528	5952	x	194.76%
Entity 1	322	Yes	1020	510	1454	x	142.55%
Entity 4	866	Yes	1186	593	672	x	56.66%

All 66 events had a 100-percent pass rate showing no degradation to DCS performance. With the BAL-002-WECC-2a R2 compliance waiver in effect, entities carried and deployed enough reserves for post disturbance ACE recovery. Also, Spinning Reserve more than the required 50 percent was carried during all but three events. Of the remaining 63, on average the entity was carrying 166.38 percent Spinning Reserve as opposed to 50 percent Spinning Reserve required by the standard. In the remaining three events, the entities carried an average of 5.3 percent less Spinning Reserve than mandated.[9]

Western Interconnection frequency performance was assessed to further determine the impact of the field test on the Interconnection. Frequency performance data was collected for the 32 events having a verified resource loss of more than 700 MW.

According to NERC, Essential Reliability Services (ERS) Measure 4[10] is a comprehensive set of Frequency Response measures capturing speed of Frequency Response and response withdrawal at all relevant time frames:

- Point A to C frequency response in MW/0.1 Hz;
- Point A to B frequency response in MW/0.1 Hz (similar to Adequate Level of Reliability (ALR)-12);
- C:B Ratio;
- C:C' Ratio; and
- Three time-based measures: t0 to tC, tC to tC', and t0 to tC'.

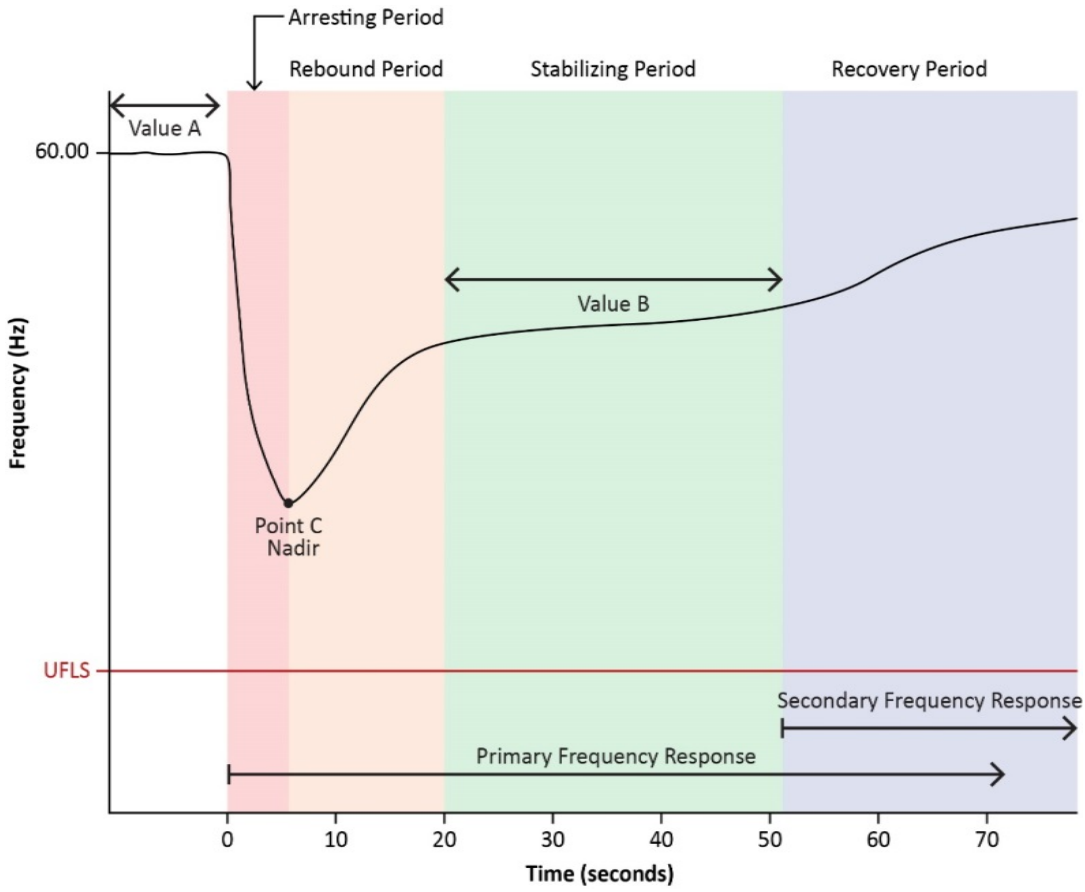
Figure 1 shows a frequency deviation due to a loss of generation resource and the methodology for calculating frequency response. The event starts at time t0. Value A is the average frequency from t-16 to t-2 seconds, Point C is the lowest frequency point observed in the first 12 seconds, and Value B is the

[9] This analysis does not speculate on why reporting entities carried more reserve than required. It only notes that excess reserves were carried.

[10] Please note that, although similar in title, *NERC's Essential Reliability Services (ERS) Measure 4* (page 8) is different from *NERC's State of Reliability Report, Metric M-4* (page 9).

average from t+20 to t+52 seconds. Point C′ occurs when the frequency after 52 seconds falls below either the Point C (12 seconds) or average Value B (20–52 seconds), as illustrated below.

Figure 1—Frequency Deviation due to Loss of Generation Resource



Per the NERC State of Reliability Report, Metric M-4 has two parts of interest: 1) performance of the Western Interconnection to arrest the frequency decline after a loss of generation event to prevent activation of underfrequency load shedding (UFLS), and 2) performance of the Western Interconnection to stabilize quickly at a high enough frequency to successfully respond to a second frequency event, should one occur.[11]

- Arresting Period: In 2017, the Western Interconnection experienced an event in which the Point C nadir was 59.697 Hz, resulting in a Point C to UFLS margin of 0.197 Hz, the smallest margin since a 0.171-Hz event in 2014. The resource MW losses for these two events were 2,685 MW and 2,826 MW, respectively. This is more than double the mean resource MW loss for each year and larger than the Resource Contingency Criteria of 2,626 MW, which is defined in the 2016

[11] NERC State of Reliability, June 2018, Appendix E: Frequency Response Statistics and Essential Reliability Services, DADS Metric 4: Performance—Demand Response Events by Month—Dispatched vs. Realized, page 112. https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_2018_SOR_06202018_Final.pdf

Frequency Response Annual Analysis and used to calculate 2017 IFRO. Over the 2013–2017 operating years, the Western Interconnection trend was neither statistically improving nor declining. This indicates that the BAL-002-WECC-2a field test did not adversely impact Western Interconnection arresting period frequency performance.

- Stabilizing Period: The mean frequency response in 2017 of 1,836 MW/0.1 Hz was the highest of all years evaluated in this report. The Western Interconnection had no events in 2017 in which its interconnection frequency response measure (IFRM) was below its IFRO, including the event noted above, wherein the Point C nadir to UFLS margin was less than 0.200 Hz. Frequency response over the 2013–2017 operating years indicated that the Western Interconnection experienced significant improvement during the stabilizing period. This indicates that the BAL-002-WECC-2a field test did not adversely impact Western Interconnection stabilizing period frequency performance.

Figure 2—Table 2.1 from NERC 2018 State of Reliability Report, June 2018

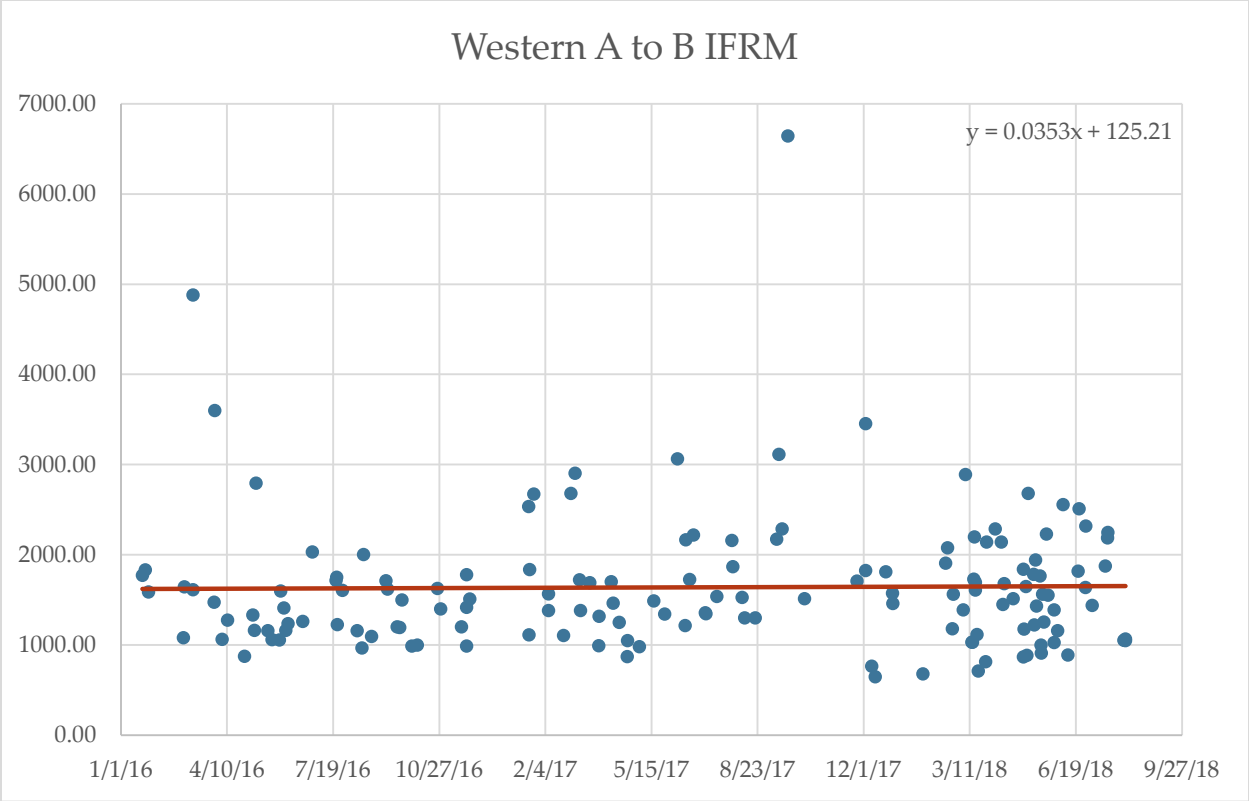
Table 2.1: Interconnection Performance Summary Statistics

Interconnection	2017 OY Largest Resource Loss		2017 OY Lowest A-B IFRM Performance		2013–2017 OY Arresting Period Performance Trend	2013–2017 OY Stabilizing Period Performance Trend
	MW Loss	UFLS Margin (Hz)	MW Loss	UFLS Margin (Hz)		
Eastern	1,661	0.453	511	0.472	Improving	No Change
Texas	1,219	0.433	369	0.603	Improving	Improving
Quebec	954	0.873	314	1.199	Improving	No Change
Western	2,776	0.210	383	0.450	No Change	Improving

Below is a summary of Western Interconnection frequency performance metrics:

1. A to B frequency response shows the effectiveness of primary frequency response in stabilizing frequency after a large frequency excursion. This measure is the conventional means of calculating Frequency Response as the ratio of net MW lost to the difference between Point A and Point B frequency values.

Figure 3—A to B IFRM



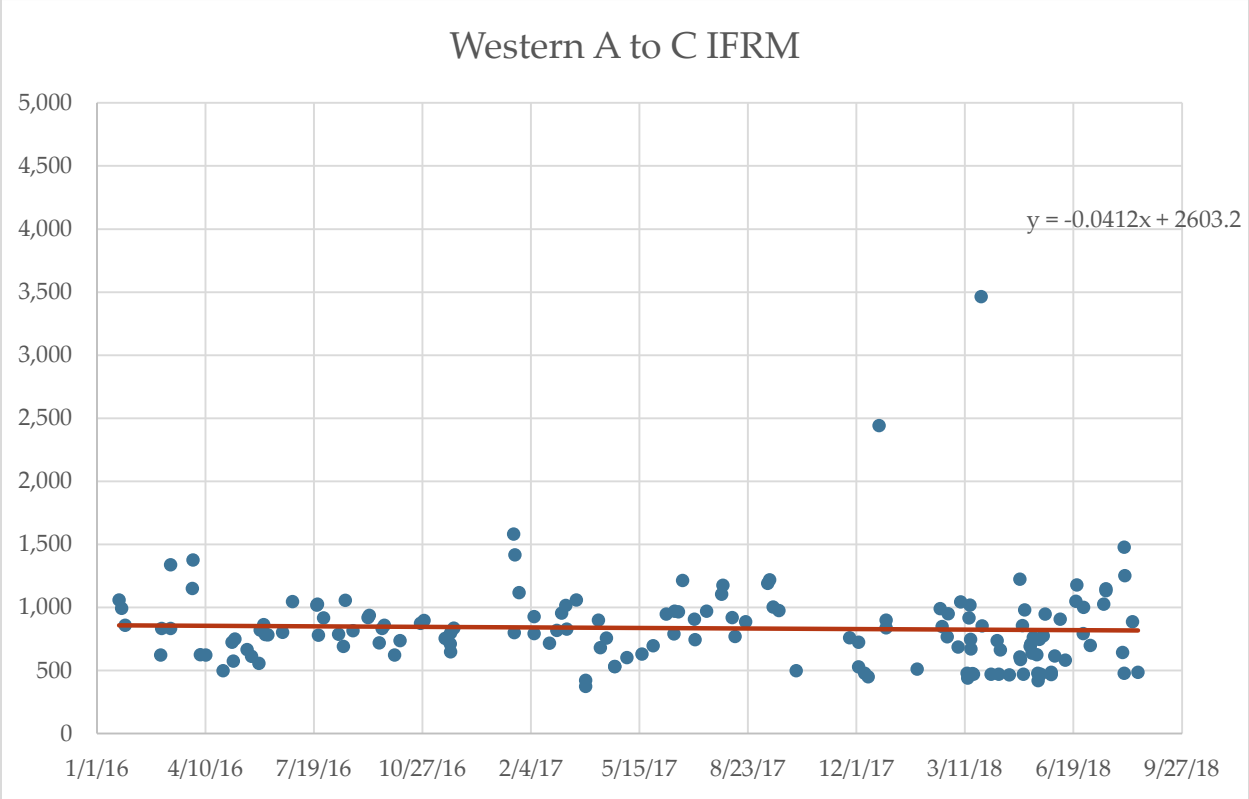
An increasing trend indicates that frequency response is improving. The Western Interconnection A to C metric shows no degradation.

For Example:

- 60.0 Hz pre-event (A frequency), Loss of 1,000 MW, 59.9 Hz primary frequency response (B frequency)
  - A to B Measure = 1,000 MW/0.1 HZ
- 60.0 Hz pre-event (A frequency), Loss of 1,500 MW, 59.9 Hz primary frequency response (B frequency)
  - A to B Measure = 1,500 MW/0.1 HZ
  - A to B measure increases, showing that larger loss of resource results in same post-event disturbance
- 60.0 Hz pre-event (A frequency), Loss of 1,000 MW, 59.92 Hz primary frequency response (B frequency)
  - A to B Measure = 1,250 MW/0.1 HZ
  - A to B measure increases, showing that the same loss in resource results in higher post-event (primary frequency response measure)

2. A to C frequency response shows the impacts of inertial response, load response (load damping), and initial governor response. Governor response is triggered immediately after frequency exceeds a pre-set deadband; however, depending on generator technology, full governor response may require up to 30 seconds to be fully deployed. This measure is calculated as the ratio of net megawatts lost to the difference between Point A and Point C frequency values.

Figure 4—A to C IFRM



An increasing trend indicates that frequency response is improving. The Western Interconnection A to C metric shows no degradation.

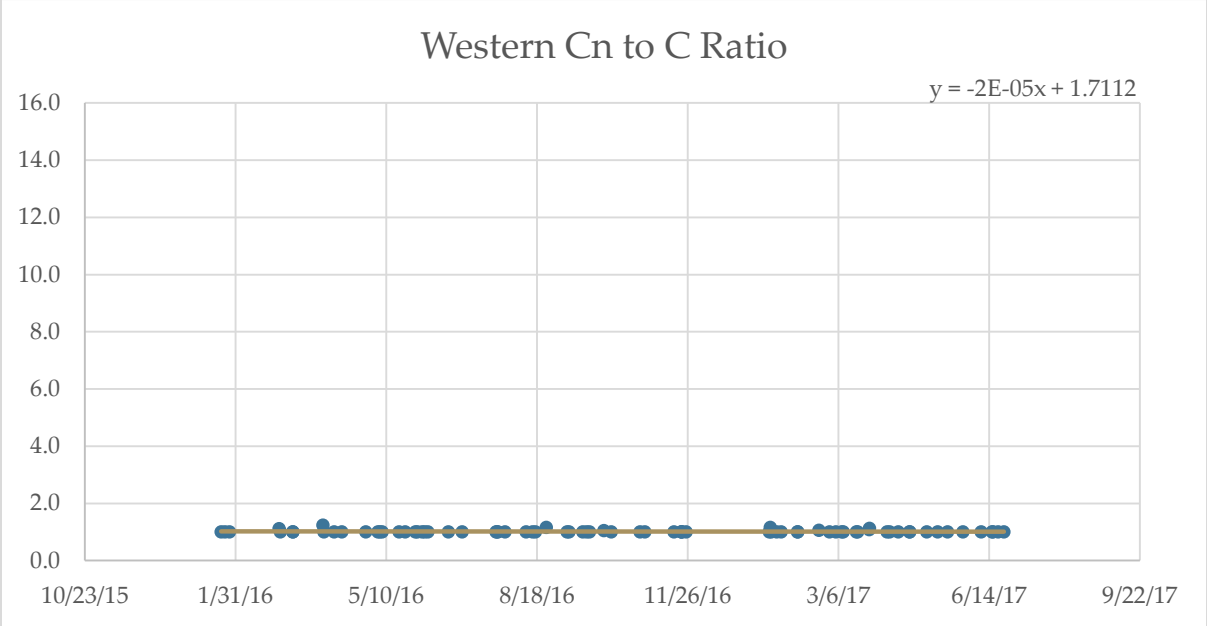
For Example:

- 60.0 Hz pre-event (A frequency), Loss of 1000 MW, 59.85 Hz lowest frequency (C frequency)
  - A to C Measure = 667 MW/0.1 HZ
- 60.0 Hz pre-event (A frequency), Loss of 1500 MW, 59.85 Hz lowest frequency (C frequency)
  - A to C Measure = 1000 MW/0.1 HZ
  - A to C measure increases, representing that larger loss of resource results in same post event disturbance

- 60.0 Hz pre-event (A frequency), Loss of 1000 MW, 59.90 Hz lowest frequency (C frequency)
  - A to C Measure = 1000 MW/0.1 HZ
  - A to C measure increases, representing that the same loss in resource results in higher post event (primary frequency response measure)

3. Cn to C is the ratio between the absolute frequency minimum (Point Cn) caused by governor withdrawal and the initial nadir (Point C). This metric measures withdrawal of primary frequency response. A response greater than 1.0 indicates withdrawal. A declining trend is an indication of improving primary frequency response. The Western Interconnection has shown no indications of response withdrawal.

Figure 5—Cn to C Ratio



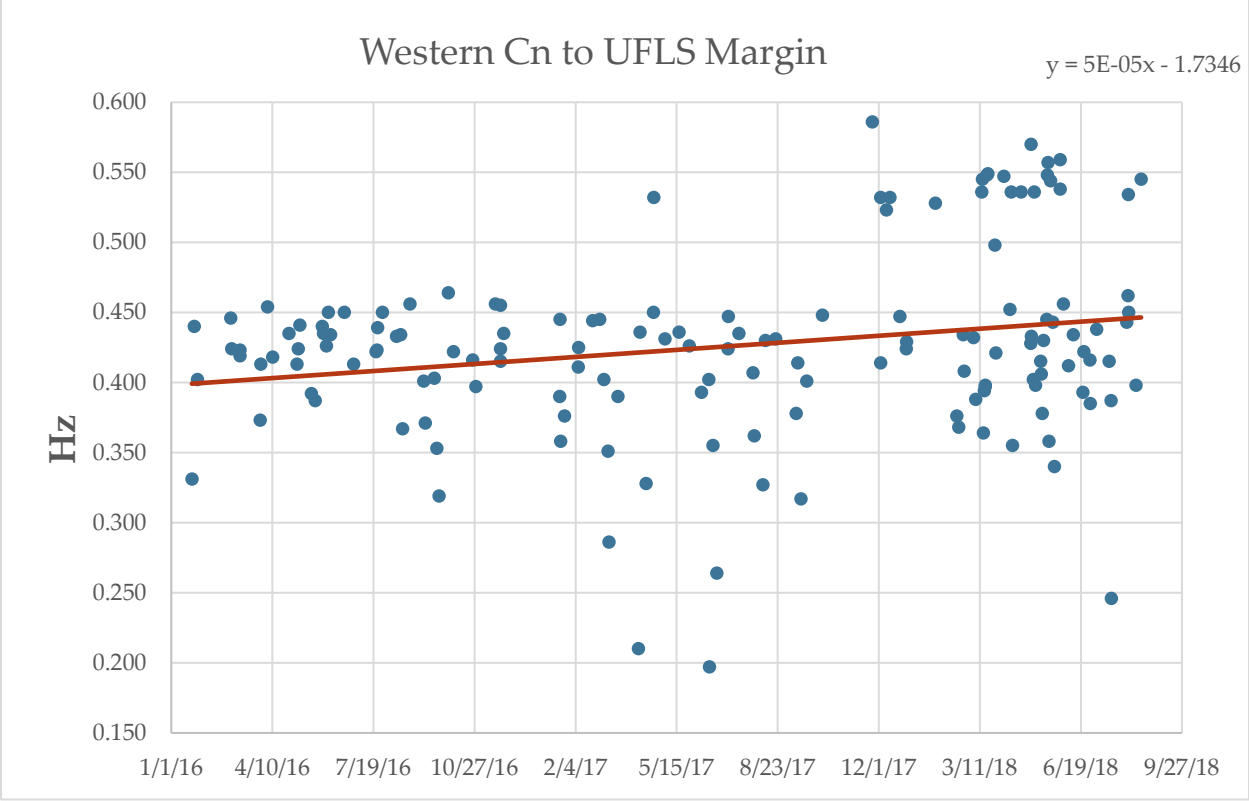
When this white paper was drafted, Cn data was only publicly available through August 2017. However, in addition to trended data, the NERC Frequency Response Annual Analysis, published November 2018, also shows that the Western Interconnection continues to experience no frequency response withdrawal during the BAL-002-WECC-2a field test.

Figure 6—Table 2.2 from NERC 2018 Frequency Response Annual Analysis, November 2018

Table 2.2: Statistical Analysis of the Adjustment for C' Nadir (BC'_{adj})						
Interconnection	Number of Events Analyzed	C' Lower than B	C' Lower than C	Mean Difference	Standard Deviation	BC'ADJ (95% Quantile)
Eastern	112	66	34	0.005	0.003	0.006
Western	86	45	0	N/A	N/A	N/A
ERCOT	143	61	2	N/A	N/A	N/A
Québec	135	31	12	-0.019	0.028	-0.004

4. Cn to UFLS ratio measures the margin between the frequency nadir and the first step in UFLS.

Figure 7—Cn to UFLS margin



The trend does show a statistical increase in UFLS margin. It should also be noted that the magnitude of the resource loss has a direct impact on Interconnection performance calculation as measured by IFRMs and Point C to UFLS margins. During 2017 and 2018, there were three events in which the

resource loss was 2,776 MW, 2,685 MW, and 2741 MW; more than double the mean resource MW loss for each year and larger than the defined Resource Contingency Criteria of 2,626 MW.[12]

One event occurred on April 6, 2017, 11:00 p.m. PDT when the field test was not in effect and the other two events on June 16, 2017, at 5:14 a.m. PDT and July 18, 2018, at 5:30 p.m. PDT when the field test was in effect. All events, however, had comparable results and significant UFLS margin before and after the field test. Also, all three events had an IFRM that exceeded the IFRO.

Per the WECC Off-Nominal Frequency Load Shedding Plan (UFLSP), load shedding occurs sequentially in five blocks with a minimum separation of 0.1 Hz between steps. UFLS entities taking part in the UFLS plan (aka, Coordinated Plan) are required to shed their first block of load as soon as frequency has declined to 59.5 Hz.[13]

[12] See the 2017 Frequency Response Annual Analysis https://www.nerc.com/comm/OC/Documents/2017_FRAA_Final_20171113.pdf#search=2017%20Frequency%20Response%20Annual%20Analysis

[13] "UFLS Entities participating in the Coordinated Plan are required to shed their first block of load as soon as frequency has declined to 59.5 Hz, with additional minimum requirements for further load shedding steps" (as set forth in the accompanying table)." WECC Off-Nominal Frequency Load Shedding Plan, Coordinated Plans, P. 1a, page 8, December 5, 2012.

WECC receives data used in its analyses from a wide variety of sources. WECC strives to source its data from reliable entities and undertakes reasonable efforts to validate the accuracy of the data used. WECC believes the data contained herein and used in its analyses is accurate and reliable. However, WECC disclaims any and all representations, guarantees, warranties, and liability for the information contained herein and any use thereof. Persons who use and rely on the information contained herein do so at their own risk.

Attachment E7
Posting 2 - Redline
WECC-0115 Contingency Reserve
Request to Retire Requirement R2

Field Test Results
BAL-002-WECC-~~2~~2a
Retirement of Requirement R2

WECC-0115 BAL-002-WECC-~~2~~2a
Request to Retire Requirement R2
Standard Drafting Team

~~January 14~~March 5, 2019

Posting 2 January 2019

155 North 400 West, Suite 200
Salt Lake City, Utah 84103-1114

Executive Summary[1]

After conducting a field test from May 1, 2017 through April 30, 2018, the WECC ~~concluded there would be no detrimental impact to the reliability of the Western Interconnection if~~ -0115 BAL-002-WECC-~~2~~2a, Contingency Reserve, Request to Retire Requirement R2 ~~were to be~~Drafting Team (DT) concluded that if Requirement R2 is retired~~.~~, it is unlikely to result in any detrimental impact to reliability.

On May 6, 2015, WECC received Standard Authorization Request (SAR) WECC -0115 BAL-002-WECC -~~2~~2a Contingency Reserve, Request to Retire Requirement R2 (R2) requesting retirement of R2 and its associated compliance elements ~~(WECC BAL).~~ The SAR asserted that on April 1, 2016, R2 would become redundant to BAL-003-1.1 Frequency Response and Frequency Bias Settings, Requirement R1 ~~(NERC BAL).~~

From May 1, 2017 through April 30, 2018, WECC conducted a NERC-approved field test to determine the impact on reliability in the event R2 was retired.[2] A compliance waiver for R2 was granted beginning on May 1, 2017 and concluding on May 1, 2019.

To enable WECC to monitor the reliability impacts of the field test, as a condition to participation in the field test, and to meet conditions specified by NERC in approving WECC's request for a field test, WECC required United States entities to provide specified information regarding the quantity of reserve carried during the field test period. As seen in the following sections, that data showed no detrimental impact to reliability in the event R2 is retired.

Project WECC-0115 will not be balloted until this report is presented for review to the appropriate WECC Ballot Pool and the NERC requirements of the NERC Rules of Procedure, 6.3 Communication and Coordination for All Types of Field Tests and Data Analyses have been met by NERC.

Posting 2 January 18, 2019

[1] This document was updated to WECC's newest template when Posting 2 was finalized. This document can be reviewed in its original format at https://www.wecc.org/Reliability/WECC-0115%20Posting%202%20BAL-002-WECC-2%20Request%20to%20Retire%20R2%20-%20Redlined%20in%20Response%20to%20Comments%203-1-2019.docx. Its updated format is presented with this filing as WECC-0115 BAL-002-WECC3 – Contingency Reserve – Attachment E6 – Posting 2 Clean.

[2] The field test was approved by NERC in late March 2017 and conducted per NERC Standards Processes Manual, Section 6.2, Field Tests and Data Analysis for Validation of Requirement.

Table of Contents

Introduction **1**

Field Test Description **1**

Field Test Analysis and Results **3**

DCS Event Field Test Data 3

Posting 2 January 18, 2019

Introduction

On May 6, 2015, WECC received Standard Authorization Request (SAR) WECC-0115 BAL-002-WECC-~~2~~2a, Contingency Reserve requesting retirement of Requirement R2 (R2) of that standard. The SAR was deemed complete the same day. The SAR asserted that on April 1, 2016, Requirement R2 would become redundant to ~~NERC~~ BAL-003-1.1, Requirement R1, Frequency Response and Frequency Bias Setting ~~(NERC BAL)~~.

On June 23, 2015, the WECC Standards Committee (WSC) approved the SAR after a favorable vetting by the WECC Operating Committee Steering Committee (OC; June 9, 2015) and the Joint Guidance Committee (JGC; May 27, 2015).

From October 22 through December 8, 2015, the project was posted once for comment, during which stakeholders were asked a single question:

> Do you agree that WECC Regional Standard BAL-002-WECC-2[3], Contingency Reserve, Requirement R2 should be retired as of the effective date of NERC Standard BAL-003-1[4] (BAL-003), Frequency Response and Frequency Bias Setting, Requirement R1?

Three entities responded to the Posting and were in favor of retirement.[5] After discussion with WECC staff[6], the DT and WECC staff were in accord that a field trial should be pursued to evaluate the impact of retiring R2.

A NERC-approved field test was conducted from May 1, 2017 through April 30, 2018. The data from that field test formed the foundation of this paper and was posted for comment, appearing as Posting 2 of this project. Posting 2 received three comments, one in favor of retirement and two suggesting caution.

Field Test Description

Data Source and Description

Posting 2 January 18, 2019

[3] Over the course of this project, the BAL-002-WECC-2 designation changed to BAL-002-WECC-2a on January 24, 2017 (FERC Docket No. RD17-3-000. The BAL-003-1 designation changed to BAL-003-1.1 on November 13, 2015, in FERC Docket RD15-6-000.

[4] BAL-003-1, Frequency Response and Frequency Bias Setting is approved by the Federal Energy Regulatory Commission (March 24, 2014) and has an enforcement date of April 1, 2016.

[5] Xcel Energy, Bonneville Power Administration, and the Western Electricity Coordinating Council (WECC)

[6] Mr. Steven Rueckert, WECC Director of Standards and Mr. Phil O'Donnell, WECC Manager, Operations and Planning Audits and Investigations

The field test data was requested from each Balancing Authority and each Reserve Sharing Group subject to ~~Requirement~~ R2 ~~of the BAL~~. Data was received by WECC through an existing online WECC portal for receipt of such reports.

The data ~~requested~~request included the following information:

1) For any reportable Disturbance Control Standard (DCS) event, the date and time of the event, the required amount of Contingency Reserves at the time of the event, the actual amount of Operating Reserves – Spinning at the time of the event, and the actual DCS performance.[7]

2) For all instances of a loss of resources 700 MW or greater, whether it is a reportable DCS event or not, the date and time of the event, the name of the resource(s), and the total MW loss.

Objective

The field test was designed to determine whether retirement of R2 would have any negative impact on grid reliability. To make that determination, the test examined the impact on Disturbance Control Standard (DCS[8]) performance and frequency response within the Western Interconnection.

Overview

The first metric, DCS performance, monitored the performance of each Reserve Sharing Group (RSG) and each Balancing Authority (BA) that was *not* a member of an RSG, for every reportable DCS event, to determine whether any of the participants were unable to meet the DCS recovery period for a DCS event. Additional information was requested from the participants to provide information to calculate the ratio for required contingency reserve to Operating Reserve-Spinning for each qualified event.

The second metric watched system performance for any loss of resources greater than 700 MW and watched for any negative impact on frequency response.[9] Information for this metric was collected by using the same information that is used by NERC to collect information to perform analysis on interconnection frequency response analysis for the NERC State of Reliability and Frequency Response Annual Analysis reports.

Posting 2 January 18, 2019

[7] During the field test, data collection only the DCS responsible entity was required to provide data during DCS events. Entities that did not have a reportable DCS event were not requested to provide data.

[8] "The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range." NERC Glossary of Terms Used in Reliability Standards (Glossary)

[9] The DT noted that the WECC Interconnection Frequency Response Obligation (IFRO) is roughly -840 MW per 0.1 HZ. The 700 MW loss was chosen as a more conservative number than the IFRO and represents a value suitably large to cause a significant frequency excursion. For illustrative purposes only see Frequency Response Analysis Tool, Dmitry Kosterev, Bonneville Power Administration, 2014. https://www.wecc.org/Reliability/Frequency%20Response%20Analysis%20-%20Dmitry%20Kosterev.pdf

Field Test Analysis and Results

BAL-002-WECC-~~2~~2a, Requirement R2 was originally intended to accomplish two purposes: 1) aid in frequency recovery (through governor action) for large generation loss events across the Western Interconnection, and 2) provide a part of the Contingency Reserves (on-~~-~~line generation minus 10-minute response) for generation trip events within the BA or RSG, if the party is an RSG member. With the implementation of new standards and an evolution of generation resources in the Western Interconnection the rational of the ~~Standards Authorization Request~~SAR was based on the presumptions that BAL-002-WECC-~~2~~2a, Requirement R2 became redundant as of the April 1, 2016 effective date of BAL-003-1.1 Frequency Response and Frequency Bias Setting, and that with its retirement neither interconnection frequency performance metrics nor Disturbance Control Standards (DCS) performance would degrade.

With the implementation of ~~NERC~~ BAL-003-01.1, frequency ~~responsive reserve~~response became a measurable quantity, and the field test provided entities a compliance waiver for WECC BAL-002-WECC-~~2~~2a Requirement R2, thus decoupling DCS and frequency response. Entities were ultimately responsible to ensure both reliability performance metrics were met. Based on ~~the~~that rational, the data captured from the field test ~~will is~~was used in conjunction with interconnection frequency response performance data to assess any impact to individual DCS performance as well as overall interconnection frequency performance.

Data Description

Data received as part of the field test covered ~~sixty-six~~66 DCS events. During each of those events, entities were required to provide data to help assess DCS performance including: Contingency Reserve Obligation, Required Spin (assuming no compliance waiver), Actual Spin, and whether ~~ACE~~Area Control Error recovery was met to successfully pass the DCS event. Reference "DCS Event Field Test Data" below for the data set collected.

DCS Event Field Test Data

Entity #	Reported MW Loss	DCS Event	Contingency (Cont) Reserve Obligation	Required Spin	Actual Spin	Pass(x)	Cont/Spin (Pre-Contingency Value)
Entity 3	530	Yes	585	293	878	x	150.09%
Entity 3	480	Yes	585	293	1165	x	199.15%
Entity 5	341	Yes	2624	1312	5595	x	213.22%
Entity 5	309	Yes	2528	1264	4095	x	161.99%
Entity 5	310	Yes	2830	1415	4428	x	156.47%
Entity 5	294	Yes	2992	1496	4010	x	134.02%
Entity 5	480	Yes	2349	1174.5	4360	x	185.61%
Entity 5	375	Yes	3068	1534	4986	x	162.52%

Posting 2 January 18, 2019

Entity 5	393	Yes	3106	1553	3989	x	128.43%
Entity 5	587	Yes	2373	1187	4483	x	188.92%
Entity 5	628	Yes	3124	1562	4201	x	134.48%
Entity 5	388	Yes	3211	1606	4217	x	131.33%
Entity 5	838	Yes	2988	1494	4223	x	141.33%
Entity 5	353	Yes	3234	1617	4658	x	144.03%
Entity 2	655	Yes	656	328	552	x	84.26%
Entity 5	356	Yes	3646	1823	5956	x	163.36%
Entity 5	619	Yes	3732	1866	6193	x	165.94%
Entity 2	430	Yes	468	234	417	x	89.11%
Entity 5	513	Yes	3514	1757	6063	x	172.54%
Entity 5	519	Yes	2823	1412	6001	x	212.58%
Entity 5	748	Yes	3688	1844	6271	x	170.04%
Entity 5	630	Yes	3024	1512	6680	x	220.90%
Entity 2	**442**	**Yes**	**538**	**269**	**231**	**x**	**42.97%**
Entity 5	506	Yes	3610	1805	6703	x	185.68%
Entity 5	760	Yes	3742	1871	6133	x	163.90%
Entity 5	522	Yes	3612	1806	5698	x	157.75%
Entity 5	1061	Yes	3791	1896	6799	x	179.35%
Entity 5	411	Yes	2964	1482	5358	x	180.77%
Entity 5	1882	Yes	2497	1249	4952	x	198.32%
Entity 5	486	Yes	3536	1768	5855	x	165.58%
Entity 5	475	Yes	3422	1711	6647	x	194.24%
Entity 5	723	Yes	3006	1503	8401	x	279.47%
Entity 5	796	Yes	3293	1647	5844	x	177.47%
Entity 5	492	Yes	3174	1587	5111	x	161.03%
Entity 5	460	Yes	5129	2565	9318	x	181.67%
Entity 5	398	Yes	5614	2807	11920	x	212.33%
Entity 5	1150	Yes	5231	2616	13142	x	251.23%
Entity 5	1699	Yes	6028	3014	9288	x	154.08%
Entity 5	786	Yes	5874	2937	9350	x	159.18%
Entity 5	479	Yes	5155	2578	14798	x	287.06%
Entity 3	538	Yes	585	293	1329	x	227.23%
Entity 5	714	Yes	5869	2935	11056	x	188.38%
Entity 5	656	Yes	6090	3045	14291	x	234.66%
Entity 5	760	Yes	5517	2759	8679	x	157.31%
Entity 3	790	Yes	790	395	1607	x	203.42%
Entity 2	496	Yes	573	286	379	x	66.15%
Entity 5	1046	Yes	8090	4045	12613	x	155.91%
Entity 5	493	Yes	7099	3550	12659	x	178.32%
Entity 5	651	Yes	3351	1676	5962	x	177.92%
Entity 1	388	Yes	1040	520	979	x	94.13%
Entity 4	851	Yes	2181	1091	1091	x	50.02%

Posting 2 January 18

Entity 1	970	Yes	1037	519	1151	x	110.99%
Entity 4	1059	Yes	1175	588	600	x	51.06%
Entity 3	582	Yes	790	395	924	x	116.96%
Entity 2	**800**	**Yes**	**565**	**283**	**234**	**x**	**41.44%**
Entity 1	471	Yes	1040	520	1359	x	130.67%
Entity 1	699	Yes	1041	521	1426	x	136.98%
Entity 4	**817**	**Yes**	**1543**	**772**	**768**	**x**	**49.77%**
Entity 5	1026	Yes	2832	1416	6038	x	213.21%
Entity 5	850	Yes	2741	1371	6543	x	238.71%
Entity 5	660	Yes	2691	1346	5911	x	219.66%
Entity 1	500	Yes	1040	520	1589	x	152.79%
Entity 5	506	Yes	3206	1603	5893	x	183.81%
Entity 5	707	Yes	3056	1528	5952	x	194.76%
Entity 1	322	Yes	1020	510	1454	x	142.55%
Entity 4	866	Yes	1186	593	672	x	56.66%

All ~~sixty-six~~66 events were passed successfully demonstrating a 100~~%~~ percent pass rate and signaling no degradation to DCS performance. With the BAL-002-WECC-~~2~~2a R2 compliance waiver in effect, entities carried and deployed sufficient reserves necessary for post disturbance ACE recovery. Additionally, Spinning Reserve exceeding the required 50~~%~~ percent was carried during all but three events. Of the remaining 63 events, on average the entity was carrying 166.38~~%~~ percent Spinning Reserve as opposed 50~~%~~ percent Spinning Reserve required by the standard. In the remaining three events, the entities carried an average of 5.3~~%~~ percent less Spinning Reserve than mandated. ~~It can only be speculation as to why entities were carrying greater than 50% Spinning Reserve during events (Regulation, load ramping, renewable generation variability, Frequency Response).~~[10]

Western Interconnection frequency performance was assessed to further determine the impact of the field test on the Interconnection. Frequency performance data was collected for the 32 events having a verified resource loss of more than 700 MW.

According to NERC, Essential Reliability Services (ERS) Measure 4 is a comprehensive set of frequency response measures at all relevant time frames: Point A to C frequency response in MW/0.1 Hz, Point A to B frequency response in MW/0.1 Hz (similar to Adequate ~~level~~Level of Reliability (ALR) -12), C:B Ratio, C:C' Ratio as well as three time-based measures (t0 to tC, tC to tC', t0 to tC'), capturing speed of frequency response and response withdrawal.[11] The figure illustrates a frequency deviation due to a loss of generation resource and the methodology for calculating frequency response. The event starts at time t0. Value A is the average frequency from t-16 to t-2 seconds, Point C is the lowest frequency

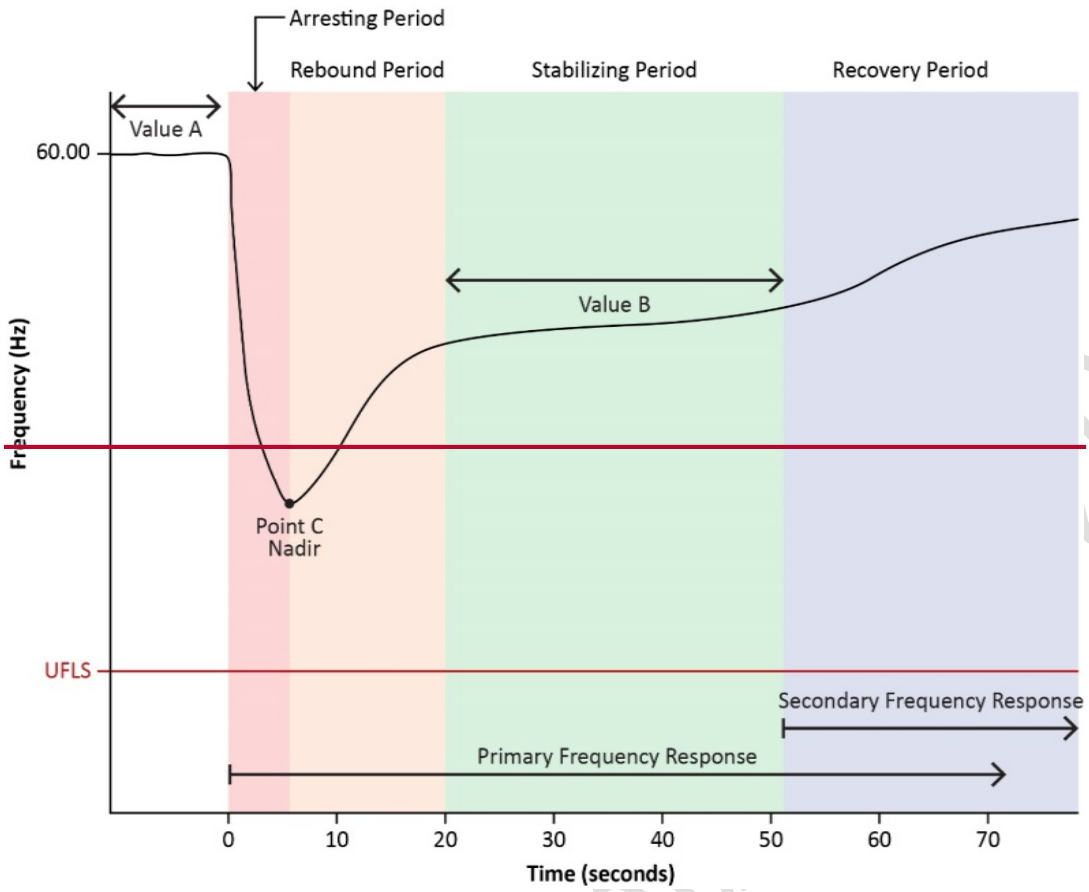
[10] This analysis does not speculate on why reporting entities carried more reserve than required. It only notes the empirical fact that reserves in excess were indeed carried.

[11] Please note that although similar in title, *NERC's Essential Reliability Services (ERS) Measure 4* (white paper page 5) is not the same as *NERC's State of Reliability Report, Metric M-4* (page 6).

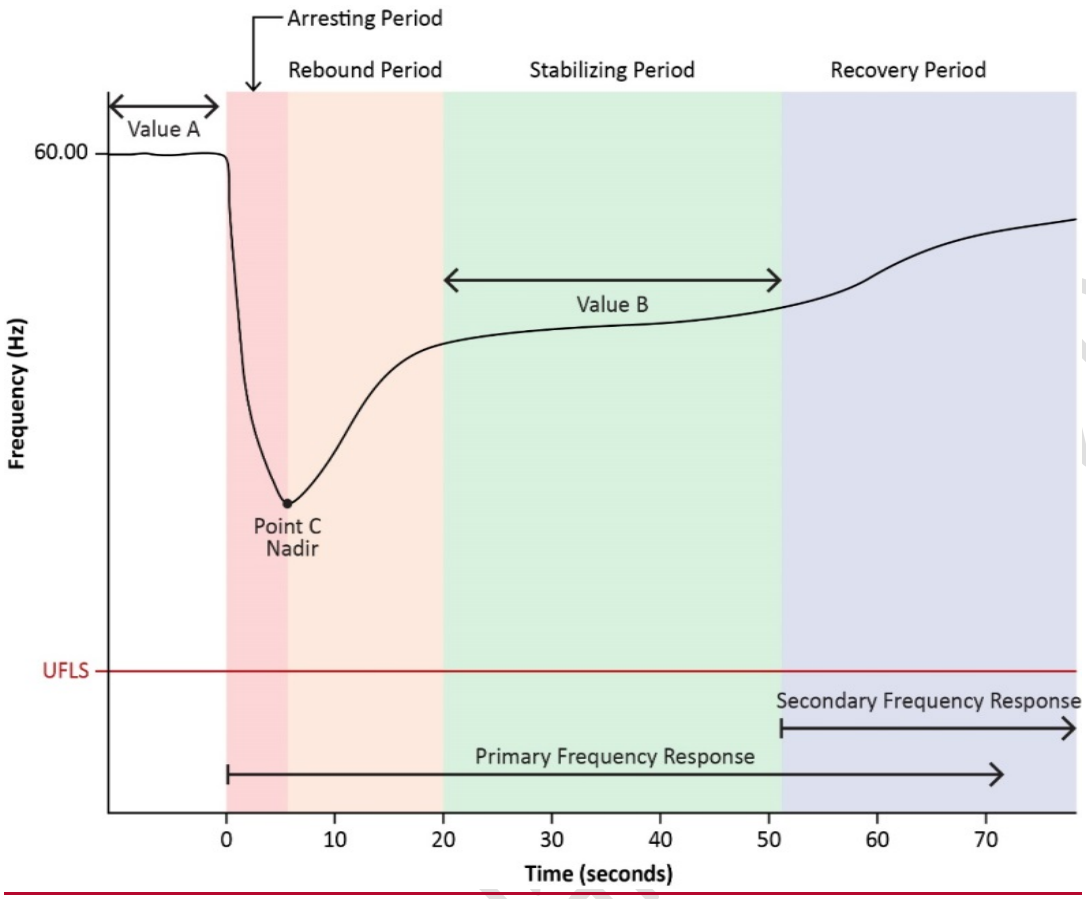
Posting 2 January 18, 2

point observed in the first 12 seconds and Value B is the average from t+20 to t+52 seconds. Point C' occurs when the frequency after 52 seconds falls below either the Point C (12 seconds) or average Value B (20 – 52 seconds), as illustrated below.

Posting 2 January 18, 2019



Posting 2 Jan 2019



Per the NERC State of Reliability Report, Metric M-4 has two components of primary interest: 1) performance of the Western Interconnection to arrest the frequency decline after a loss of generation event to prevent activation of Under Frequency Load Shedding, and 2) performance of the Western Interconnection to stabilize quickly at a high enough frequency to successfully respond to a second frequency event, should one occur.[12]

- Arresting Period: In 2017, the Western Interconnection experienced an event where the Point C nadir was 59.697 Hz, resulting in a Point C to UFLS margin of 0.197 Hz, the smallest margin since a 0.171 Hz event in 2014. The resource MW loss for these two events were 2,685 MW and 2,826 MW, respectively, more than double the mean resource MW loss for each year and larger Resource Contingency Criteria of 2,626 MW defined in the 2016 Frequency Response Annual Analysis and used to calculate 2017 Interconnection Frequency Response Obligation (IFRO). Over the 2013–2017 operating years, the Western Interconnection trend was neither

[12] NERC Sate of Reliability, June 2018, Appendix E: Frequency Response Statistics and Essential Reliability Services, DADS Metric 4: Performance—Demand Response Events by Month—Dispatched vs. Realized, page 112. https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_2018_SOR_06202018_Final.pdf

statistically improving nor declining. This indicates that the BAL-002-WECC-~~2~~2a field test did not adversely impact Western Interconnection arresting period frequency performance.

- Stabilizing period: The mean frequency response in 2017 of 1,836 MW / 0.1 Hz was the highest of all years evaluated in this report. The WI had no events in 2017 where its IFRM was below its IFRO, including the event noted above where the Point C nadir to UFLS margin was less than 0.200 Hz. Frequency response over the 2013–2017 operating years indicated that the Western Interconnection experienced statistically significant improvement during the stabilizing period. This indicates that the BAL-002-WECC-~~2~~2a field test did not adversely impact western interconnection stabilizing period frequency performance

Table 2.1 provides a summary of the Interconnection performance statistics discussed above.

Table 2.1: Interconnection Performance Summary Statistics

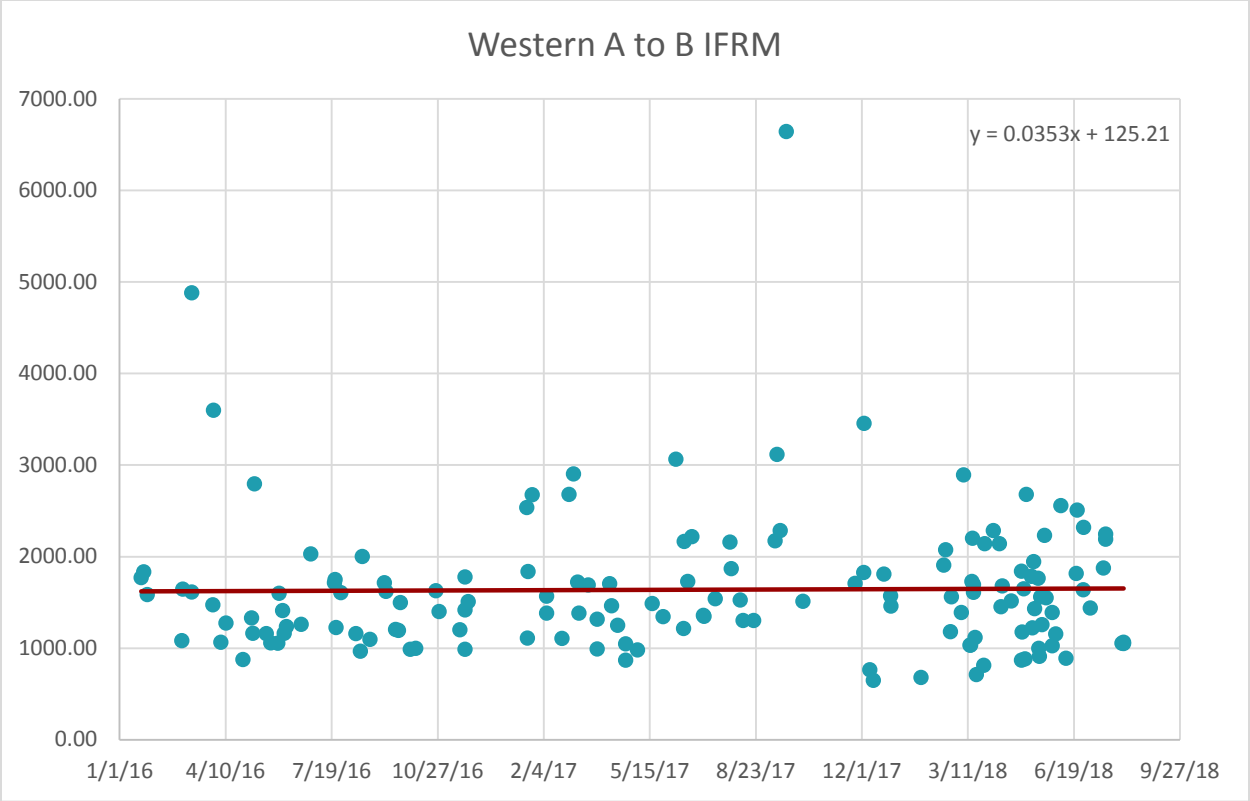
Interconnection	2017 OY Largest Resource Loss		2017 OY Lowest A-B IFRM Performance		2013–2017 OY Arresting Period Performance Trend	2013–2017 OY Stabilizing Period Performance Trend
	MW Loss	UFLS Margin (Hz)	MW Loss	UFLS Margin (Hz)		
Eastern	1,661	0.453	511	0.472	Improving	No Change
Texas	1,219	0.433	369	0.603	Improving	Improving
Quebec	954	0.873	314	1.199	Improving	No Change
Western	2,776	0.210	383	0.450	No Change	Improving

**NERC 2018 State of Reliability Report published June 2018*

Below is a summary of Western Interconnection frequency performance metrics:

1) A to B frequency response captures the effectiveness of primary frequency response in stabilizing frequency following a large frequency excursion. This Measure is the conventional means of calculating Frequency Response as the ratio of net MW lost to the difference between Point A and Point B frequency values.

Posting 2 January 2019



An increasing trend over time indicates that frequency response is improving. -The Western Interconnection A to C metric shows no degradation.

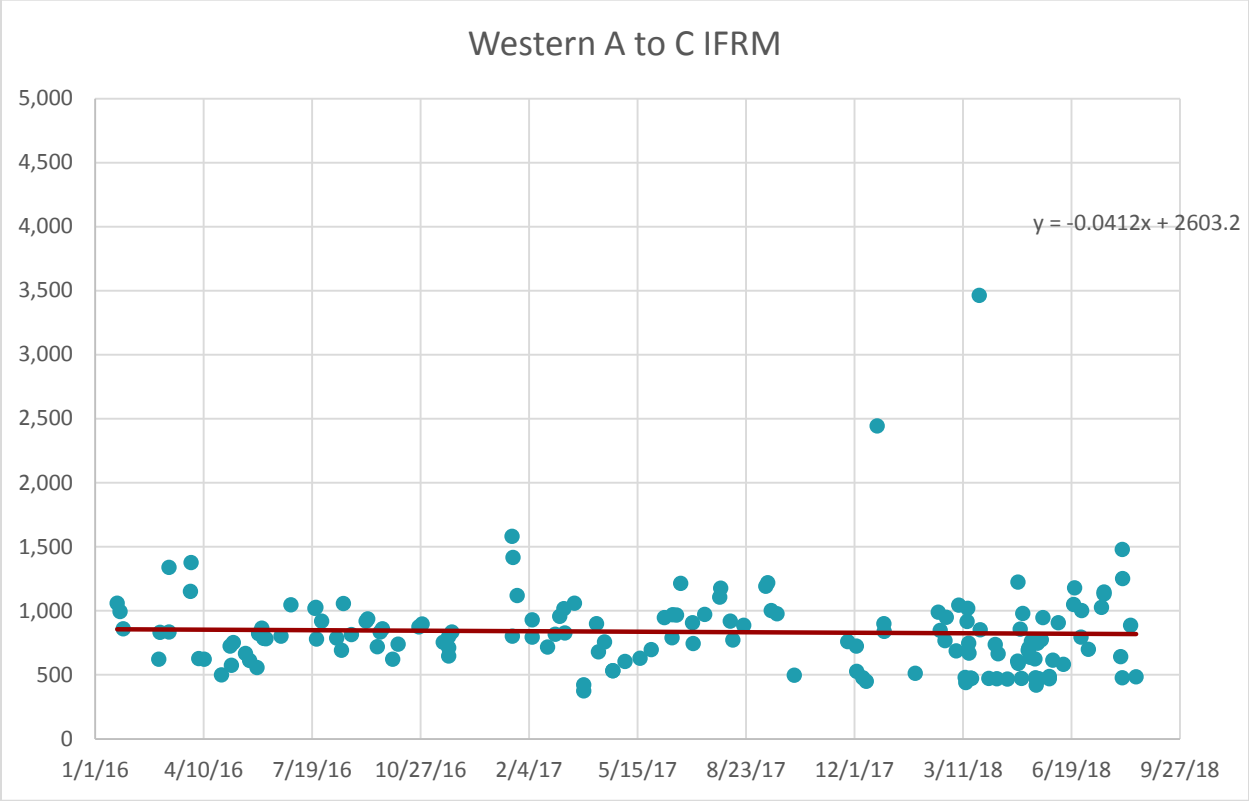
For Example:

- 60.0 Hz pre-event (A frequency), Loss of 1000 MW, 59.9 Hz primary frequency response (B frequency)
  - A to B Measure = 1000 MW/0.1 HZ
- 60.0 Hz pre-event (A frequency), Loss of 1500 MW, 59.9 Hz primary frequency response (B frequency)
  - A to B Measure = 1500 MW/0.1 HZ
  - A to B measure increases, representing that larger loss of resource results in same post event disturbance
- 60.0 Hz pre-event (A frequency), Loss of 1000 MW, 59.92 Hz primary frequency response (B frequency)
  - A to B Measure = 1250 MW/0.1 HZ
  - A to B measure increases, representing that the same loss in resource results in higher post event (primary frequency response measure)

2) A to C frequency response captures the impacts of inertial response, load response (load damping) and initial governor response (governor response is triggered immediately after

Posting 2 Janua

frequency exceeds a pre-set deadband; however, depending on generator technology, full governor response may require up to 30 seconds to be fully deployed). This Measure is calculated as the ratio of net megawatts lost to the difference between Point A and Point C frequency values.



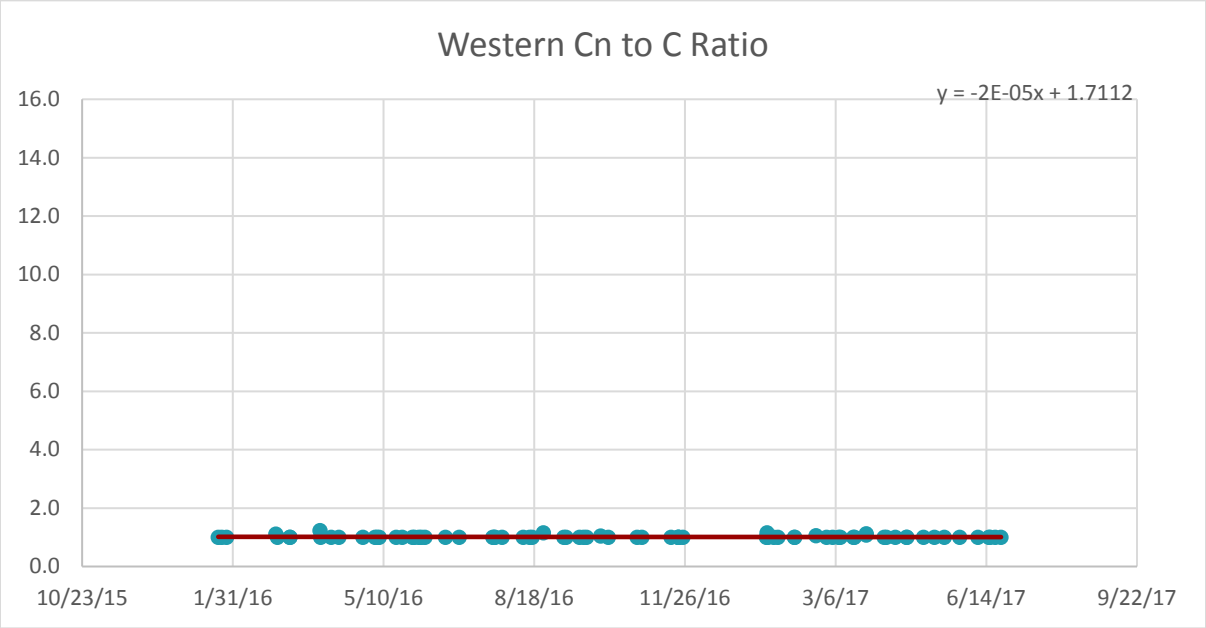
An increasing trend over time indicates that frequency response is improving. The Western Interconnection A to C metric shows no degradation.

- Generic Example:
  - 60.0 Hz pre-event (A frequency), Loss of 1000 MW, 59.85 Hz lowest frequency (C frequency)
    - A to C Measure = 667 MW/0.1 HZ
  - 60.0 Hz pre-event (A frequency), Loss of 1500 MW, 59.85 Hz lowest frequency (C frequency)
    - A to C Measure = 1000 MW/0.1 HZ
    - A to C measure increases, representing that larger loss of resource results in same post event disturbance
  - 60.0 Hz pre-event (A frequency), Loss of 1000 MW, 59.90 Hz lowest frequency (C frequency)
    - A to C Measure = 1000 MW/0.1 HZ

Posting 2

- A to C measure increases, representing that the same loss in resource results in higher post event (primary frequency response measure)

3) Cn to C is the ratio between the absolute frequency minimum (Point Cn) caused by governor withdrawal and the initial nadir (Point C). This metric measures withdrawal of primary frequency response. A response greater than 1.0 indicates withdrawal. A declining trend is an indication of improving primary frequency response. The Western Interconnection has shown no indications of response withdrawal.



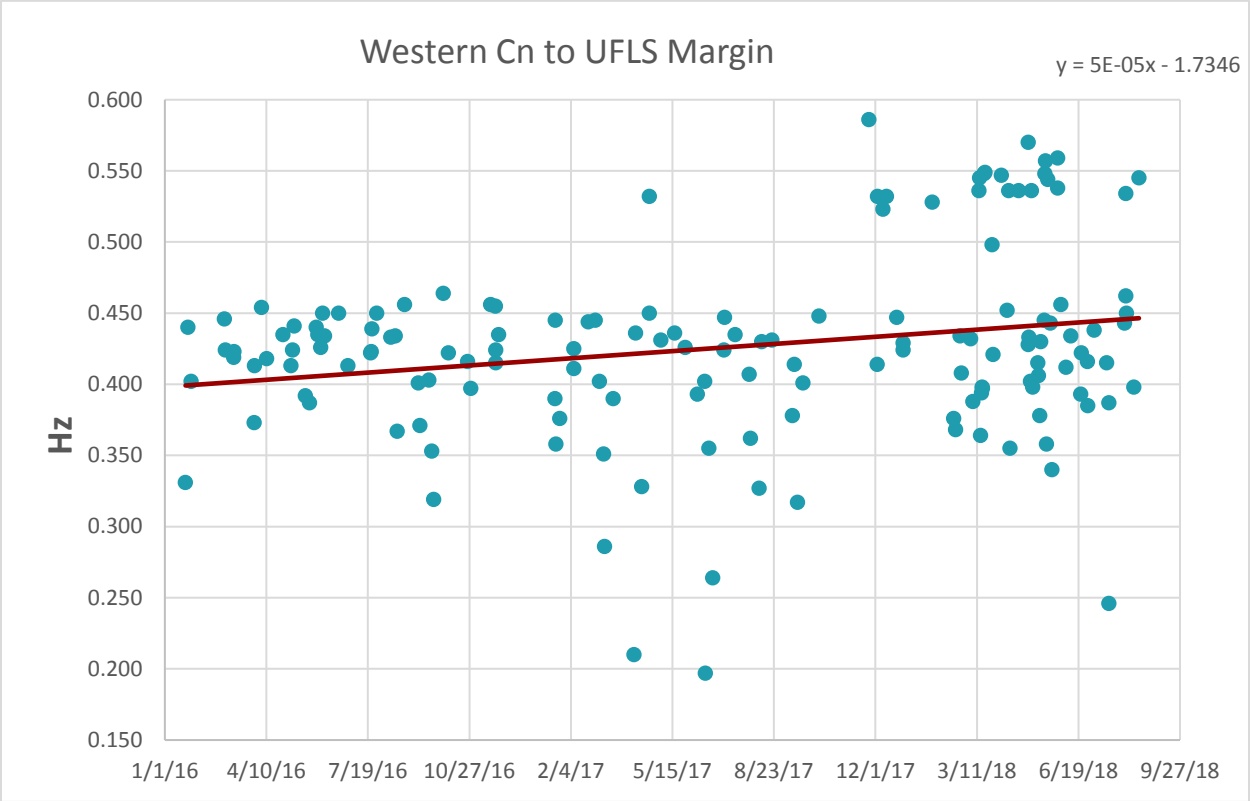
~~At the time of the drafting~~When this white paper was drafted, Cn data was only publicly available through August 2017. However, in addition to trended data, the NERC Frequency Response Annual Analysis published November 2018 also demonstrates the Western Interconnection ~~has continued~~continues to ~~not~~ experience no frequency response withdraw during the time of the BAL-002-WECC-~~2~~2a Field Test.

Table 2.2: Statistical Analysis of the Adjustment for C' Nadir (BC'_{adj})

Interconnection	Number of Events Analyzed	C' Lower than B	C' Lower than C	Mean Difference	Standard Deviation	BC'ADJ (95% Quantile)
Eastern	112	66	34	0.005	0.003	0.006
Western	86	45	0	N/A	N/A	N/A
ERCOT	143	61	2	N/A	N/A	N/A
Québec	135	31	12	-0.019	0.028	-0.004

**NERC 2018 Frequency Response Annual Analysis published November 2018*

4) Cn to USLF ratio measures the margin between the frequency nadir and the first step in Under Frequency Load Shed (UFLS).



The trend does show a statistical increase in UFLS margin. It should also be noted that the magnitude of the resource loss has a direct impact on Interconnection performance calculation as measured by IFRMs and Point C to UFLS margins. During 2017 and 2018, there were three events where the resource loss was 2,776 MW, 2,685 MW and 2741 MW, more than double the mean resource MW loss for each year and larger than the defined Resource Contingency Criteria of 2,626 MW.[13]

One event occurred on April 6, 2017, 11:00 p.m. (Pacific) when the field test was not in effect and the other two events on June 16, 2017 at 5:14 a.m. (Pacific) and July 18, 2018 at 5:30 p.m. (Pacific) when the field test was in effect; however, all events had comparable results and significant UFLS margin before and after the field test. Additionally, all three events had an interconnection frequency response measure (IFRM) that exceeded the interconnection frequency response obligation (IFRO~~))~~.

[13] See The 2017 Frequency Response Annual Analysis. https://www.nerc.com/comm/OC/Documents/2017_FRAA_Final_20171113.pdf#search=2017%20Frequency%20Response%20Annual%20Analysis

Per the WECC Off Nominal Frequency Load Shedding Plan (UFLSP), load shedding occurs sequentially in five blocks with a minimum separation between steps of 0.1 Hz. UFLS entities participating in the UFLS plan (AKA: Coordinated Plan) are required to shed their first block of load as soon as frequency has declined to 59.5 Hz.[14]

Disclaimer

WECC receives data used in its analyses from a wide variety of sources. WECC strives to source its data from reliable entities and undertakes reasonable efforts to validate the accuracy of the data used. WECC believes the data contained herein and used in its analyses is accurate and reliable. However, WECC disclaims any and all representations, guarantees, warranties, and liability for the information contained herein and any use thereof. Persons who use and rely on the information contained herein do so at their own risk.

Posting 2 January 18 2019

[14] "UFLS Entities participating in the Coordinated Plan are required to shed their first block of load as soon as frequency has declined to 59.5 Hz, with additional minimum requirements for further load shedding steps" (as set forth in the accompanying table)." WECC Off-Nominal Frequency Load Shedding Plan, Coordinated Plans, P. 1a, page 8, December 5, 2012.

Electric Reliability and Security for the West

Attachment E8
Posting 1 Response to Comments
WECC-0115 Contingency Reserve
Request to Retire Requirement R2

Posting 1[1]

The WECC-0115 BAL-002-WECC-2, Request to Retire Requirement R2 Drafting Team (DT) thanks everyone who submitted comments on the proposed documents.

Posting

This project was posted for a 45-day public comment period from October 22 through December 8, 2015.

WECC distributed the notice for the posting on October 22, 2015. The DT asked stakeholders to provide feedback on the proposed document through a standardized electronic template. WECC received comments from three companies as shown in the following table.

Location of Comments

All comments received on the project can be viewed in their original format on the WECC-0115 project page under the "Submit and Review Comments" accordion.

Changes in Response to Comment

After consideration of comments received, the DT took the following action:

No changes were made to the Posting 1 document.

After direct discussion with WECC staff commenters (Mr. Steven Rueckert and Mr. Phil O'Donnell), the drafting team and WECC staff were in accord that a field trial should be pursued to evaluate the impact of retirement of BAL-002-WECC-2, Requirement R2.

Effective Date

The effective date for this project is to be coincident with the effective date of BAL-003-1, Frequency Response and Frequency Bias Setting, Requirement R1.

---

[1] This document has been updated to WECC's most recent document template. It can be viewed in its original format at https://www.wecc.org/Reliability/WECC-0115%20Posting%201%20BAL-002-WECC-2%20Retire%20R2%20-%20Response%20to%20Comments%2010-22%20through%2012-8-2015.docx.

BAL-003-1, Frequency Response and Frequency Bias Setting is approved by the Federal Energy Regulatory Commission (March 24, 2014) and has an enforcement date of April 1, 2016.

Action Plan

On December 17, 2015, the WECC-0115 DT agreed by majority vote to pursue a field trial to determine the potential effects of retiring BAL-002-WECC-2, Requirement R2. Mr. W. Shannon Black, WECC Consultant, will draft and circulate the proposed trial for internal comment by the drafting team as well as WECC Standards, Operations, and Compliance departments. The team will reconvene on January 7, 2016, from 10:00 a.m. to 12:00 p.m. with the goal of finalizing the field trial proposal for presentation to the NERC.

Contacts and Appeals

If you feel your comment has been omitted or overlooked, please contact W. Shannon Black, WECC Consultant, at (503) 307-5782. In addition, there is a WECC Reliability Standards appeals process.

Commenter		Organization
1	William Franklin	Xcel Energy
2	Aaron Paulson	On Behalf of the Bonneville Power Administration
3	Steven Ashbaker Steven Rueckert Phil O'Donnell	Western Electricity Coordinating Council (WECC)

Index to Questions, Comments, and Responses

Question

1. The drafting team welcomes comments on all aspects of the document.

1. The drafting team welcomes comments on all aspects of the document.

Summary Consideration: See summary in the preamble of this document.	
Commenter	**Comment**
William Franklin, Xcel Energy	Public Service Company of Colorado supports retirement of BAL-002-WECC-2, Contingency Reserve, Requirement R2 as of the effective date of BAL-003, Frequency Response and Frequency Bias Setting, Requirement R1. Lacking a better approach R2 served the Region well over the past years and decades but it is now time to retire it. R2 was intended to accomplish two purposes; aid in frequency recovery (through governor action) for large generation loss events across the WECC, and provide a part of the contingency reserves (on line generation-10-minute response) for generation trip events within the BA or RSG if party is a member. However spinning reserve in R2 is somewhat vague and has no performance-based compliance metric. R2 is functionally replaced by BAL-003 for frequency recovery. BAL-003 will serve this first purpose in a more straight forward manner; response time, responsibility and compliance metric are each well-defined and geared specifically to help the interconnection recover frequency in a reliable manner. With regard to the second purpose, local loss of generation, BAL-002-WECC-2, without R2, will not be diluted. It will continue to require the same total amount of contingency reserves, only the somewhat vague requirement of carrying a 10-minute, 50 percent spinning reserve as part of the overall contingency reserve will have been appropriately removed. With no reduction in reliability retirement of R2 will remove sources of possible confusion, and unsupportable overlap between R2 and BAL-003. Thanks for the opportunity to comment.
Response	
The drafting team thanks Xcel for its comments and its continued support in the standards development process.	

Summary Consideration: See summary in the preamble of this document.	
Commenter	**Comment**
Bonneville Power Administration	**Comments on retirement of WECC BAL-002 R2** **Answer to Survey:** BPA strongly supports that the requirement of WECC Regional Standard BAL-002-WECC-2, Contingency Reserve, Requirement R2, should be retired as of the effective date of NERC Standard BAL-003-1 (BAL-003), Requirement R1. BAL-003-1, Frequency Response and Frequency Bias Setting is approved by the Federal Energy Regulatory Commission (March 24, 2014) and has an enforcement date of April 1, 2016. **Comments:** With the retirement of WECC BAL-002 R2, and the adoption of NERC BAL-003-01, frequency responsive reserve becomes a measurable quantity and no longer needs to be covered within a 50% spinning reserve requirement. BAL-003-01 is a more applicable standard for measuring frequency response and meets the original intent of WECC BAL-002 R2, which was put in place because; it was, "in the absence of a frequency response standard…capable of arresting a frequency excursion." (WECC-0115 Posting 1). With this in mind, BPA would like to provide some further thoughts on the decision to retire WECC BAL-002 R2. 1. Outside of the technical aspects of frequency response, a key reason to have the BAL-002 R2 standard retired as of the effective date of NERC Standard BAL-003-01 relates to comments made in WECC-0115 Posting 1, that states "Retention of both WECC BAL Requirement R2 as well as BAL-003 Requirement R1 could lead to confusion and the needless procurement of additional reserve, thereby increasing costs without benefit." BPA agrees fully that multiple requirements to hold spinning reserve and also meet FRO requirements, double up on the BA requirement to meet the same goal.

Summary Consideration: See summary in the preamble of this document.	
Commenter	**Comment**
	2. BPA agrees that BAL-003-01 FRM is a better indicator of frequency response than a 50% spin requirement. While BAL-003-001 provides a measure for frequency response, it places no requirement on capacity that needs to be held by a BA in order to meet the standard. This needs to be determined by the BA planners/operators themselves, using their knowledge of equipment capability. Without other operational changes (adjusting plant controls, governor tuning), a BA would need to maintain its current level of spinning reserves to statistically maintain its historical measures of frequency response in the short term. Without other changes (i.e. tuning to plant controls, governors, additional units) the lessening of spinning reserve amounts would likely lessen statistical measures of frequency response in WECC. With this in mind, BPA sees that NERC BAL-003-01 is a better driver for BA's to study their actual online frequency response capability, than WECC BAL-002 R2. 3. The WECC standard was a good stop-gap for frequency response with the absence of a NERC frequency response standard. However, spinning reserve does not have a one-to-one correlation to frequency response. A good example of this is a situation where a BA is carrying spinning reserves on only a few generating units. The spinning reserve requirement is met; however, the BA does not have as much frequency response as if the spinning reserve was carried on a greater number of responsive units. In order to create a more accurate estimate of frequency response capacity online, BPA is studying: the number of units online, the max capacity of those units, current generation of those units, governor droop, actual tests of unit performance, and how much of governor response is met in the 20-52 second measurement window defined in NERC BAL-003-01.

Summary Consideration: See summary in the preamble of this document.	
Commenter	**Comment**
	4. One more point BPA would like to make regarding comments in WECC-0115 Posting 1, is in regards to the statement that, "*Requirement R2, Section 2.2 can be retired because it is already addressed in Requirement R2, Section 2.1. Section 2.1 requires the applicable entity to carry reserve 'that is immediately and automatically responsive to frequency.' Section 2.2 requires the applicable entity to carry reserves 'capable of fully responding within ten minutes.' Section 2.1's immediate response-time renders the Section 2.2 ten-minute response time moot. The drafting team notes the language is a carryover from the MORC and should be updated through retirement.*" BPA would like to point out that it is not a strong argument to say that "Requirement R2, Section 2.2 can be retired because it is already addressed in Requirement R2, Section 2.1," because section 2.1 is going to be retired as well. BPA suggests that since Section 2.2 is a sub-requirement of R2, with R2 retired then 2.2 would stand by itself and would make the statement that 'Reserve must be capable of fully responding within 10 minutes.' This 10-minute response is already covered in Requirement R1, 1.4.
Response	
The DT appreciates BPA's support in the retirement of the Requirement. The DT also appreciates BPA's continued involvement in the standards development process.	

Summary Consideration: See summary in the preamble of this document.	
Commenter	**Comment**
WECC Staff Steve Ashbaker: WECC, ashbaker@wecc.biz Phil O'Donnell: WECC, podonnell@wecc.biz	Thank you for the opportunity to provide comments on the proposed retirement of BAL-002-WECC-2, Requirement R2. We are concerned that the project to retire BAL-002-WECC-2, Requirement R2 may be moving forward too fast, without the proper evaluations being made prior to retirement. It is our understanding that BAL-003 and Frequency Response are characteristics of the first few seconds after a disturbance

Summary Consideration: See summary in the preamble of this document.	
Commenter	**Comment**
Steve Rueckert: WECC, steve@wecc.biz	and are based on available on-line reserves, the associated inertia of the on-line generation and the frequency dependency of the load on line at the time. Contrarily, BAL-002 and BAL-002-WECC-2 address contingency reserves, which are used to restore ACE within 15 minutes of a disturbance. There is no indication that a Frequency Response Measure (FRM) that complies with the Requirements of BAL-003 will ensure ACE will be restored in accordance with the requirements of BAL-002 unless the amount of Responsive Reserves required to comply with BAL-003 was equal to or greater than the disturbance. BAL-003 was required due to the systematic retirement of heavy thermal and large hydro and the replacement with various types of low inertia and no inertia resources. We recognize that BAL-002-WECC-2 requires only half of the total amount of contingency reserves to be online and responsive to frequency, so that alone is not enough to ensure compliance with the DCS requirement, and that it requires operator intervention to meet DCS. However, we suspect that Requirement R2 of BAL-002-WECC-2 is one of the major contributors to WECC's relatively good frequency response when compared to the Eastern Interconnection. We question at this point how a Frequency Response Sharing Group (FRSG) or Balancing Authority that is not part of a FRSG will know how much on-line, responsive resources they will need to meet the Requirements of BAL-003. We have some concern that due to the monitoring process for BAL-003 and entity may find out too late that they are going to be non-compliant. For the reasons above we suggest a more cautious approach to the potential retirement of BAL-002-WECC-2, Requirement R2 and offer two options for consideration. The first option is that we do not retire BAL-002-WECC-2, Requirement R2 until at least one year beyond the effective date of BAL-003. This

Summary Consideration: See summary in the preamble of this document.	
Commenter	**Comment**
	would allow us to determine if the requirement is too demanding, which would be demonstrated by responsible entities greatly exceeding FRM compliance. If that were the case, we could feel comfortable retiring Requirement R2. The second option would be for WECC to seek a waiver of BAL-002-WECC-2, Requirement R2 for at least a year so that we can conduct a field trial to ensure that not keeping BAL-002-WECC-2, Requirement R2 effective will not lead to a substantial decrease in frequency response in the West. Thank you for your consideration.
Response	
WECC commenters (Mr. Steven Rueckert and Mr. Phil O'Donnell) were in attendance at the drafting team meeting during which these comments were addressed. After a thorough discussion of the above issues both the drafting team and the commenters were in accord that the concerns raised could be addressed by pursuing a field trial to examine system performance in the absence of BAL-002-WECC-2, Requirement R2. The drafting team discussed the outline for the proposed trial and will target finalization of the proposal when they reconvene. The proposal will be vetted with WECC Standards (Rueckert), Operations (Ashbaker), and Compliance (O'Donnell). The primary WECC liaison is proposed to be Mr. Tim Reynolds in his role as WECC staff liaison for the WECC Performance Work Group under the WECC Operating Committee. Commenters agreed that each of the sub-issues raised in their comments need not be addressed in lieu of pursuing the proposed field trial.	

Posting 2[1]

The WECC-0115 BAL-002-WECC-2a, Contingency Reserve, Request to Retire Requirement R2 Drafting Team (DT) thanks everyone who submitted comments on the proposed document.

Posting

This project was posted for a 30-day public comment period from January 18 through February 18, 2019.

WECC distributed the notice for the posting on January 14, 2019. The DT asked stakeholders to provide feedback on the proposed document through a standardized electronic template. Three comments were received on this posting.

Location of Comments

All comments received on the project can be viewed in their original format on the WECC-0115 project page under the "Submit and Review" accordion.

Changes in Response to Comment

After considering all comments received, the DT opted for the following changes:

The opening sentence of the executive summary is to read as follows:

> After conducting a field test from May 1, 2017, through April 30, 2018, the WECC-0115 BAL-002-WECC-2a, Contingency Reserve, Request to Retire Requirement R2 Drafting Team (DT) concluded that if Requirement R2 is retired, *it is unlikely to result in any detrimental impact to reliability.* (Emphasis added.)

The following sentence was added to the closing comment of the Introduction:

[1] This document can be reviewed in its original format at https://www.wecc.org/Reliability/WECC-0115%20Posting%202%20BAL-002-WECC-2%20Request%20to%20Retire%20R2%20-%20Tech%20Editor%20Approved.docx.

> The data from that field test formed the foundation of this paper and was posted for comment, appearing as Posting 2 of this project. Posting 2 received three comments, one in favor of retirement and two suggesting caution.

The following footnote regarding why the 700-MW threshold was used was added to the Overview:

> The DT noted that the WECC Interconnection Frequency Response Obligation (IFRO) is roughly -840 MW per 0.1 HZ. The 700 MW loss was chosen as a more conservative number than the IFRO and represents a value suitably large to cause a significant frequency excursion. For illustrative purposes only see Frequency Response Analysis Tool, Dmitry Kosterev, Bonneville Power Administration, 2014. https://www.wecc.org/Reliability/Frequency%20Response%20Analysis%20-%20Dmitry%20Kosterev.pdf

The following footnote was added to the DCS Field Test section to highlight the DT's lack of speculation as to why the field test showed additional reserves carried or whether future results will be the same:

> This analysis does not speculate on why reporting entities carried more reserve than required. It only notes the empirical fact that reserves in excess were indeed carried.

The following footnote was added to the DCS Field Test section to highlight the difference between to similar terms:

> Please note that although similar in title, *NERC's Essential Reliability Services (ERS) Measure 4* (white paper page 5) is not the same as *NERC's State of Reliability Report, Metric M-4* (page 6).

Although the following style changes were made, this document is still pending full review by the WECC technical editor. Changes made include:

- References updated from BAL-002-WECC-2 to BAL-002-WECC-2a, along with use of the full reference in lieu of abbreviation.
- References updated from BAL-003-1 to BAL-003-1.1, along with use of the full reference in lieu of abbreviation.

Minority View

The DT opted not to include speculation as to why more reserves were carried than anticipated nor to speculate as to whether future performance would replicate those amounts.

The DT disagreed with Powerex that retirement of Requirement R2: 1) was premature given the present status of BAL-003-1.1 and 2) would make BAL-002-WECC-2a less stringent.

The DT maintains that retirement of Requirement R2 is warranted because the requirement is redundant to BAL-003-1.1. In its Posting 1, Response to Comments, the DT provided a detailed explanation regarding this issue.

Effective Date

The effective date for this project is to be coincident with the effective date of BAL-003-1.1, Frequency Response and Frequency Bias Setting, Requirement R1.

BAL-003-1.1, Frequency Response and Frequency Bias Setting is approved by the Federal Energy Regulatory Commission (March 24, 2014) and has an enforcement date of April 1, 2016.

Justification of Effective Date

The reliability-related substance of WECC-0115 BAL-002-WECC-2a Contingency Reserve, Requirement R2 is contained in BAL-003-1.1 Frequency Response and Frequency Bias, Requirement R1.

Because the reliability task is addressed in BAL-003-1.1 Requirement R1, BAL-002-WECC-2a Requirement R2 is redundant and can be retired.

Impact on Other Standards

As to other existing and proposed standards, the drafting team notes that some confusion may arise as to how the retirement of WECC-0115 BAL-002-WECC-2a, Requirement R2 may interplay with the existing BAL-002-1, Disturbance Control Performance standard. BAL-002-1, Requirement R2.3 requires the applicable entity (the Regional Reliability Organization *or* the Reserve Sharing group) to "specify its Contingency Reserve policies, including … (R2.3) … the permissible mix of Operating Reserve – Spinning and Operating Reserve—Supplemental that may be included in Contingency Reserve." Arguably, BAL-002-WECC-2a Requirement R2 meets this requirement.

The drafting team disagrees that retention of BAL-002-WECC-2a Requirement R2 is the only means of compliance with BAL-002-1. At a high level, since BAL-002-1 has no Measure for the associated Requirement R2, how compliance might be met is unclear. Further, since the only Measure provided requires that the Balancing Authority *or* the Reserve Sharing group "shall calculate and report compliance with the Disturbance Control Standard," there is a disconnect between the required performance (have a policy) and the required Measure (perform a calculation).

Consideration of Early Compliance

The DT sees no concerns with early compliance.

Action Plan

On February 28, 2019, the WECC-0115 BAL-002-WECC-2a, Contingency Reserve, Request to Retire Requirement R2 Drafting Team agreed by majority vote to forward the project to the WECC Standards Committee (WSC) with a request for ballot. If approved, this project will retire Requirement R2 of that standard on the premise that R2 is redundant to BAL-003-1.1 Frequency Response and Frequency Bias Setting, Requirement R1.

A NERC-approved field test examining the potential impact on reliability if BAL-002-WECC-2a Requirement R2 is retired was conducted from May 1, 2017, through April 30, 2018. The drafting team examined the field test data including Disturbance Control Standard (DCS) performance and frequency response within the Western Interconnection concluding that adequate reserve was available throughout the period of the field test.

During the field test, a NERC-approved compliance waiver for Requirement R2 was in place. An extension of that waiver has been requested to run through May 1, 2020. A response to that request is pending.

The full project is available for review on the WECC website at the WECC-0115 homepage.

Contacts and Appeals

If you feel your comment has been omitted or overlooked, please contact W. Shannon Black, WECC Consultant, at (503) 307-5782. In addition, there is a WECC Reliability Standards appeals process.

Commenter		Organization
1	Andrea Jessup	Bonneville Power Administration
2	Connor Curson	Powerex Corporation
3	Adrian Andreoiu	BC Hydro

Index to Questions, Comments, and Responses

Question

1. The drafting team welcomes comments on all aspects of the document.

1. The drafting team welcomes comments on all aspects of the document.

Summary Consideration: See summary in the preamble of this document.	
Commenter	**Comment**
Andrea Jessup, Bonneville Power Administration	BPA supports the retirement of BAL-002-WECC-2. With the implementation of BAL-003 the spinning reserve requirement of BAL-002-WECC -2 has been shown to be an inappropriate and redundant measure of frequency response. A frequency responsive resource needs both capability and headroom to provide frequency response. Although BAL-002-WECC -2 states that the spinning reserve must be frequency responsive, it does not measure that frequency response nor recognize that frequency response is measured in MW/tenths of a Hertz, not MW's (e.g., a unit could say it provides a certain amount of spin, but actually provides much less frequency response when following governor droop).
Response	
The drafting team appreciates Bonneville Power Administration's longstanding commitment to the WECC Standards and Criteria development process.	
Commenter	**Comment**
Connor Curson, Powerex Corp.	Powerex appreciates the opportunity to submit comments on WECC's recently published White Paper, "Field Test Results BAL-002-WECC-2 Retirement of Requirement R2" (January 14, 2019). The White Paper, and the field test reported within the White Paper, was produced in response to a Standard Authorization Request (SAR) for retirement of BAL-002-WECC-2 R2. The SAR asserted that BAL-002-WECC-2 R2 would become redundant to BAL-003-1 Frequency Response and Frequency Bias Settings, Requirement R1. In response, the WECC conducted a NERC-approved field test to determine the impact on reliability in the event BAL-002-WECC-2 R2 was retired. The paper notes that the results of the field test indicate that "there would be no detrimental impact to the reliability of the Western Interconnection if BAL-002-WECC-2, Contingency Reserve, Requirement R2 were to be retired." Powerex respectively submits that the WECC should be cautious in making such an unequivocal statement based on the field test results.

	Powerex does not dispute that the field test demonstrated that entities carried and deployed sufficient reserves necessary for post disturbance ACE recovery with the BAL-002-WECC-2 R2 compliance waiver in effect across the field trial. However, in Powerex's view, the field test does not demonstrate that BAL-003-1 R1, as currently written, would render BAL-002-WECC-2 R2 redundant. This is due to the differences in how the two requirements are drafted: BAL-002-WECC-2 R2 is a *prescriptive* requirement that applies equally to all entities and is applicable in all hours, whereas BAL-003-1 R1 is an *after-the-fact* check that determines compliance based on an entity's performance during its *median* event of the year. Under BAL-003-1 R1, an entity could potentially carry less Frequency Response than its Frequency Response Obligation ("FRO") for more than 40% of the hours of the year, effectively leaning on other WECC entities, and still be in compliance with the standard. If enough entities are acting in a similar manner during a tail event (say, Q2, high wind), there may not be sufficient Frequency Response to avoid Under-Frequency Load-Shedding. BAL-002-WECC-2 R2 provides a floor on the amount of unloaded, synchronized generation (Spinning Reserve) that entities must carry in every hour. The White Paper doesn't quantify the risk to Frequency Response in the Western Interconnection of removing that floor. It therefore seems premature to move forward with a plan to retire BAL-002-WECC-2 R2 until a field test could demonstrate that the above noted risk is insignificant, or, that BAL-003-1 can be revised to include a focus on real-time Frequency Response such that having the extra protection of a baseline Spinning Reserve requirement is no longer required. Finally, Powerex notes that NERC regularly seeks demonstration that a replacement or retirement of a reliability standard results in a more *stringent* standard, not a *relaxation* of standards. While Powerex agrees in general that there should not be an unnecessary duplication of standards or regulations, in this instance Powerex does not believe unnecessary duplication exists. Thank you for consideration of our comments and we look forward to engaging on this topic in future meetings.

Response

The drafting team appreciates Powerex' observations and has changed the opening (and corresponding) sentence of the executive summary as follows:

> "After conducting a field test from May 1, 2017, through April 30, 2018, the WECC-0115 BAL-002-WECC-2a, Contingency Reserve, Request to Retire Requirement R2 Drafting Team (DT) concluded that if Requirement R2 is retired, *it is unlikely to result in any detrimental impact to reliability."* Emphasis added.

More Stringent

Generally, FERC will approve a Regional Reliability Standard (RRS) if the content of the RRS is either more stringent than its NERC counterpart, or the RRS covers an area not addressed in the NERC, continent-wide standard.

In June 2007, FERC approved WECC's BAL-STD-002-0, Operating Reserves (BAL-002-WECC-2a's predecessor), noting two specific attributes that made that standard more stringent than its NERC counterparts (NERC BAL-002 series of standards[2]).

> "The Commission stated that regional Reliability Standard BAL-STD-002-0 was more stringent than the NERC Reliability Standard BAL-002-0 because the WECC regional Reliability Standard required: (1) a more stringent minimum reserve requirement; and (2) restoration of contingency reserves within 60 minutes, as opposed to the 90-minute restoration period required by the NERC Reliability Standard BAL-002-0.1."[3]

More specifically, FERC found that WECC's *calculation* of minimum contingency reserves and its 60-minute restoration period were more stringent than that of NERC.[4] These two FERC-identified

[2] Since the 2005 inception of the NERC BAL-002, Disturbance Control Performance series of standards, the purpose of that NERC series has been to ensure that applicable entities could access and use sufficient Contingency Reserves to balance resources and demand until Interconnection frequency returned to normal after a disturbance. BAL-002-1, Disturbance Control Standard required applicable entities to have access to and operate Contingency Reserves, specify reserve policies, activate sufficient reserves to meet Disturbance Control Standard (DCS), and replace those reserves as needed. Successive versions of NERC's BAL-002 series added the concept of preparing for responding to Most Severe Single Contingency within a given period. BAL-002-2—Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event, Version 2 (FERC Order approved BAL-002-2. Docket No. RM16-7-000) and Version 3 (Revisions to address two FERC directives from Order No. 835, FERC Order approving BAL-002-3. Docket No. RD18-7-000).

[3] FERC Order No. 789, C. WECC Regional Reliability Standard BAL-STD-002-0, Docket No. RM13-13-000.

[4] Loc. Cit. See *1. Restoration Period for Contingency Reserve*, paragraph 9 and *2. Calculation of Minimum Contingency Reserve*, paragraph 10.

attributes are retained in BAL-002-WECC-2, Requirements R1, R3, and R4, wherein those Requirements state:

- "R1. Each [BA/RSG] shall maintain a minimum amount…"
- "R3. Each [Sink BA/RSG] shall maintain an amount…"
- "R4. Each [Source BA/RSG] shall maintain an amount…"

By contrast, Requirement R2 does not require maintenance of a specific amount of reserve; rather, R2 specifies the type or quality of reserve that must be carried. [5] This is a stated fraction of the amount of reserve required in Requirement R1. Thus, retirement of Requirement R2 has no impact on the calculation of the amount of reserves nor does it impact the 60-minute restoration period. As such, Requirement R2 can be retired without BAL-002-WECC-2 becoming less stringent.

Redundancy

As to the issue of redundancy, the WECC-0115 DT addressed this issue in detail in its Posting 1 Response to Comments.[6] Further, the DT believes retirement of Requirement R2 meets the spirit of FERC's "P81 Order."[7]

---

[5] In FERC's November 2013 order approving BAL-002-WECC-2, Contingency Reserve, FERC noted "The regional Reliability Standard applies to balancing authorities and reserve sharing groups in the WECC Region and *is meant to specify the quantity and types of contingency reserve required* to ensure reliability under normal and abnormal conditions." FERC Order 789, Summary (Emphasis added).

[6] WECC-0115 BAL-002-WECC-2, Contingency Reserve Drafting Team, Request to Retire Requirement R2, Posting 1 for 45-day Comment, October 23 through December 8, 2015, pages 2–4.

https://www.wecc.biz/Reliability/WECC-0115%20Posting%201%20BAL-002-WECC-2%20Request%20to%20Retire%20R2%20-%2010-23-2015%20through%2012-8-2015.docx

[7] Paragraph 81 ("P 81") of the FFT Order reads:

"The Commission notes that NERC's FFT initiative is predicated on the view that many violations of requirements currently included in Reliability Standards pose lesser risk to the Bulk-Power System. If so, some current requirements likely provide little protection for Bulk-Power System reliability or may be redundant. The Commission is interested in obtaining views on whether such requirements could be removed from the Reliability Standards with little effect on reliability and an increase in efficiency of the ERO compliance program. If NERC believes that specific Reliability Standards or specific requirements within certain Standards should be revised or removed, we invite NERC to make specific proposals to the Commission identifying the Standards or requirements and setting forth in detail the technical basis for its belief. In addition, or in the alternative, we invite NERC, the Regional Entities and other interested entities to propose appropriate mechanisms to identify and remove from the Commission approved Reliability Standards unnecessary or redundant requirements. We will not impose a deadline on when these comments should be submitted, but ask that to the extent such comments are submitted NERC, the Regional Entities, and interested entities coordinate to submit their respective comments concurrently." North American Electric Reliability Corporation, 138 FERC ¶ 61,193 at P 81 (2012) ("FFT Order").

Retaining Requirement R2 offers little to no added benefit to reliability because the intent of R2 was to ensure that reserve assets have specific response attributes. These are the same attributes called for in BAL-003-1.1.[8]

Commenter	Comment
Adrian Andreoiu and Tony Nguyen, BC Hydro	BC Hydro greatly appreciates the drafting team's efforts to conduct the field test and compile the results, and offers the following comments on the January 14, 2019 version of the "Field Test Results BAL-002-WECC-2 Retirement of Requirement R2" report. The first paragraph of the Executive Summary (page 1) states that "WECC concluded there would be no detrimental impact to the reliability of the Western Interconnection if BAL-002-WECC-2, Contingency Reserve, Requirement R2 were to be retired." BC Hydro recommends that this sentence be re-worded to account for the fact that the observed DCS recovery performance was recorded where, for 63 out of 66 events, the actual Spinning Reserves carried by the responsible entities were far greater than the 50% requirement. Without a clear comparison with the status prior to the Field Test, in terms of actual Spinning Reserves being carried, it seems that there is not enough support for such an unequivocal statement. A well-placed phrase such as "it appears that…" or "unlikely to cause…" might be more appropriate. In the Overview section (page 2) it may be helpful to clearly express that data used for demonstrating impacts on Frequency Response cover a period wider than the Field Test period for which the impacts on DCS Recovery is observed. As drafted, readers will have to look into details of each frequency response analysis graph to realize that fact. The statement in the last paragraph on page 2, "With the implementation of NERC BAL-003-01, frequency responsive reserve became a measurable quantity," should be clarified that only the

[8] In its order remanding BAL-002-WECC-1, FERC called for WECC to broaden the specified criteria of the equipment used to meet the requirement so that a broader range of reserve assets might be included. FERC Order 740, paragraphs 60–62, Docket No. RM09-15-000. FERC Order 789, paragraph 48.

	Frequency Response is measured for BAL-003-1, not Frequency Responsive Reserve. BC Hydro recommends expanding the last sentence of the first paragraph on page 5 into a separate paragraph to further substantiate whether the drafting team has reasons to believe that even after the retirement of the requirement R2 of BAL-002-WECC-2 the entities will continue to carry high level of Spinning Reserve, potentially by operating their system in manners that satisfy other objectives, be it environmental, economic or reliability standard compliance (particularly if a direct link to BAL-003-1 R1 can be made). BC Hydro suggests revising the last paragraph on page 5 to indicate that the ALR-12 Metric has been renamed to Metric M-4. This Metric M-4 is one of the metrics monitored by the NERC Performance Analysis Subcommittee (PAS) and is different than ERS Measure 4. If this paragraph about ERS Measure 4 is to be retained, some background info should be included to explain the difference between Metric M-4 and ERS Measure 4 to avoid confusion. It may not be necessary to retain this paragraph since it appears that all of the analysis that followed were extracted from the NERC Frequency Response Annual Analysis and NERC State of Reliability Reports and were performed for Metric M-4. If that is confirmed, BC Hydro suggests removing this entire paragraph to avoid confusion. Thank you for the opportunity to comment.

Response

The DT agrees that there are rarely certainties in future-looking analysis. As such, the tenor of the conclusion has been redrafted. Please see the above response to Powerex.

As to adding an explanation regarding why excess reserves were carried during any specific period or by any specific entity, or whether future results will be the same as the history field test, the DT would only be speculating as to the past and future motives of each entity. Thus, the DT opted not to venture a guess in its analysis. That said, there is a near certainty that some hydro-based entities will always carry large amounts of reserve due to the nature of the asset, such as water behind the dam.

As to modification of the second full paragraph of page five regarding Essential Reliability Services (ERS) Measure 4, the DT opted to retain the paragraph as it illuminates the analysis and illustrations that follow thereafter. The following footnote was added to aid in clarity:

"Please note that although similar in title, *NERC's Essential Reliability Services (ERS) Measure 4* (white paper page 5) is not the same as *NERC's State of Reliability Report, Metric M-4* (page 6)."

As to editorial modification of the Overview section to include greater detail, the DT opted not to adopt the suggestion, concluding the draft as presented sufficiently conveyed the message.

In the first sentence of page five, the word "reserve" was deleted from the phrase "frequency response reserve." The resulting sentence is as follows:

"With the implementation of NERC BAL-003-01.1, frequency response ~~reserve~~ became a measurable quantity, and the field test provided entities a compliance waiver for WECC BAL-002-WECC-2a Requirement R2, thus decoupling DCS and frequency response."

Minority Issues

Posting 1

In Posting 1, there were no minority issues; however, after direct discussion with WECC staff (Mr. Steven Rueckert and Mr. Phil O'Donnell), the drafting team (DT) concluded that a field trial should be pursued to evaluate the effects of retiring BAL-002-WECC-2a, Requirement R2.[1] After conducting the field test, the drafting team concluded that retirement of BAL-002-WECC-2a Contingency Reserve, Requirement R2 "is unlikely to result in any detrimental impact to reliability."[2]

Posting 2

In Posting 2, the DT opted not to include speculation as to why more reserves were carried than anticipated, nor to speculate as to whether future performance would replicate those amounts.

The DT disagreed with Powerex that retirement of BAL-002-WECC-2a, Requirement R2 was premature given the present status of BAL-003-1.1. The DT maintained that retirement of Requirement R2 is warranted because the requirement is redundant to BAL-003-1.1. In its Posting 1, Response to Comments, the DT gave a detailed explanation regarding this issue.

Balloting Comments

During balloting, British Columbia Hydro and Power Authority abstained from ballot but gave the following narrative, echoing the Posting 2 minority position held by Powerex:

> BAL-002-WECC-2 R2 requirement to carry spinning reserves in all hours could provide improved frequency response. The retirement of this requirement may result in Western

[1] The naming nomenclature changed during development from BAL-002-WECC-2, BAL-002-WECC-2a, and will change to BAL-002-WECC-3 if approved.

[2] Field Test Results, BAL-002-WECC-2 Retirement of Requirement R2, Executive Summary. See also Exhibit C and Attachment E8. These documents can be reviewed in their original format on the WECC-0115 project page located at https://www.wecc.org/Standards/Pages/WECC-0115.aspx.

entities' diminished frequency response performance that may not be alleviated by the current BAL-003-1.1 standard, which is under review and development under NERC Standards Development Project 2017-01.

BC Hydro recommends that the retirement of this requirement be coordinated with the revision of the BAL-003-1.1 Frequency Response and Frequency Bias Setting.

Electric Reliability and Security for the West

Attachment E11

Ballot Pool Members

WECC-0115 BAL-002-WECC-3

Contingency Reserve

Request to Retire R2

Ballot Pool Members

Project	Entity	Segment	Vote	Comment	Name
WECC-0115	British Columbia Hydro & Power Authority	Electric Generators	Abstain	BAL-002-WECC-2 R2 requirement to carry spinning reserves in all hours could provide improved frequency response. The retirement of this requirement may result in Western entities' diminished frequency response performance that may not be alleviated by the current BAL-003-1.1 standard, which is under review and development under NERC Standards Development Project 2017-01. BC Hydro recommends that the retirement of this requirement be coordinated with the revision of the BAL-003-1.1 Frequency Response and Frequency Bias Setting.	Adrian Andreoiu

Project	Entity	Segment	Vote	Comment	Name
WECC-0115	British Columbia Hydro & Power Authority	Transmission Dependent Utilities (TDU)	Abstain	BAL-002-WECC-2 R2 requirement to carry spinning reserves in all hours could provide improved frequency response. The retirement of this requirement may result in Western entities' diminished frequency response performance that may not be alleviated by the current BAL-003-1.1 standard, which is under review and development under NERC Standards Development Project 2017-01. BC Hydro recommends that the retirement of this requirement be coordinated with the revision of the BAL-003-1.1 Frequency Response and Frequency Bias Setting.	Adrian Andreoiu
WECC-0115	British Columbia Hydro & Power Authority	Transmission Owners	Abstain	BAL-002-WECC-2 R2 requirement to carry spinning reserves in all hours could provide improved frequency response. The retirement of this requirement may result in Western entities' diminished frequency response performance that may not be alleviated by the current BAL-003-1.1 standard, which is under review and development under NERC Standards Development Project 2017-01. BC Hydro recommends that the retirement of this requirement be coordinated with the revision of the BAL-003-1.1 Frequency Response and Frequency Bias Setting.	Adrian Andreoiu

Project	Entity	Segment	Vote	Comment	Name
WECC-0115	British Columbia Hydro & Power Authority	Load-Serving Entities (LSE)	Abstain	BAL-002-WECC-2 R2 requirement to carry spinning reserves in all hours could provide improved frequency response. The retirement of this requirement may result in Western entities' diminished frequency response performance that may not be alleviated by the current BAL-003-1.1 standard, which is under review and development under NERC Standards Development Project 2017-01. BC Hydro recommends that the retirement of this requirement be coordinated with the revision of the BAL-003-1.1 Frequency Response and Frequency Bias Setting.	Adrian Andreoiu
WECC-0115	Southern California Edison Company	Load-Serving Entities (LSE)	Abstain	No comments.	Romel Aquino
WECC-0115	Tacoma Power	Transmission Dependent Utilities (TDU)	Yes	0	John Nierenberg
WECC-0115	Seattle City Light	Transmission Dependent Utilities (TDU)	Yes	0	Hao Li
WECC-0115	Tacoma Power	Electric Generators	Yes	0	Karen Hedlund
WECC-0115	Platte River Power Authority	Transmission Owners	Yes	0	Matthew Thompson
WECC-0115	Tacoma Power	Load-Serving Entities (LSE)	Yes	0	Twila Hofer
WECC-0115	Bonneville Power Administration	Transmission Owners	Yes	0	Kammy Rogers-Holliday

Project	Entity	Segment	Vote	Comment	Name
WECC-0115	Bonneville Power Administration	Load-Serving Entities (LSE)	Yes	0	Rebecca Berdahl
WECC-0115	Western Area Power Administration	Electricity Brokers, Aggregators, and Marketers	Yes	0	Timothy Vigil
WECC-0115	Bonneville Power Administration	Electricity Brokers, Aggregators, and Marketers	Yes	0	Andrew Meyers
WECC-0115	California Independent System Operator	Regional Transmission Organizations (RTOs) and Independent System Operators (ISO)	Yes	0	Richard Vine
WECC-0115	Puget Sound Energy, Inc.	Electric Generators	Yes	0	Theresa Rakowsky
WECC-0115	Puget Sound Energy, Inc.	Load-Serving Entities (LSE)	Yes	0	Theresa Rakowsky
WECC-0115	Puget Sound Energy, Inc.	Transmission Owners	Yes	0	Theresa Rakowsky
WECC-0115	Los Angeles Department of Water and Power	Transmission Owners	Yes	0	Pjoy Chua
WECC-0115	Los Angeles Department of Water and Power	Load-Serving Entities (LSE)	Yes	0	Pjoy Chua
WECC-0115	Los Angeles Department of Water and Power	Electricity Brokers, Aggregators, and Marketers	Yes	0	Pjoy Chua

Project	Entity	Segment	Vote	Comment	Name
WECC-0115	Los Angeles Department of Water and Power	Electric Generators	Yes	0	Pjoy Chua
WECC-0115	Arizona Public Service Company	Load-Serving Entities (LSE)	Yes	0	Vivian Vo
WECC-0115	Arizona Public Service Company	Electric Generators	Yes	0	Kelsi Rigby
WECC-0115	Arizona Public Service Company	Electricity Brokers, Aggregators, and Marketers	Yes	0	Chinedu Ochonogor
WECC-0115	Arizona Public Service Company	Transmission Owners	Yes	0	Michelle Amarantos
WECC-0115	Public Utility District No. 1 of Chelan County	Electric Generators	Yes	0	Meaghan Connell
WECC-0115	Public Utility District No. 1 of Chelan County	Transmission Owners	Yes	0	Meaghan Connell
WECC-0115	Public Utility District No. 1 of Chelan County	Load-Serving Entities (LSE)	Yes	0	Meaghan Connell
WECC-0115	Public Utility District No. 1 of Chelan County	Electricity Brokers, Aggregators, and Marketers	Yes	0	Meaghan Connell
WECC-0115	Puget Sound Energy, Inc.	Electric Generators	Yes	0	Eleanor Ewry
WECC-0115	Platte River Power Authority	Load-Serving Entities (LSE)	Yes	0	Jeff Landis

Project	Entity	Segment	Vote	Comment	Name
WECC-0115	Platte River Power Authority	Electricity Brokers, Aggregators, and Marketers	Yes	support the retirement of BAL-002-WECC-2a, Requirement R2 on the premise that R2 is redundant to BAL-003-1.1 Frequency Response and Frequency Bias Setting. We are at the end of a 2 year field trial and have found no degradation in reliability in general and also none specific to BAL-002 or BAL-003 performance.	Sabrina Martz
WECC-0115	Platte River Power Authority	Electric Generators	Yes	0	Tyson Archie
WECC-0115	Idaho Power Company	Electricity Brokers, Aggregators, and Marketers	0	0	Laura Nelson
WECC-0115	Idaho Power Company	Load-Serving Entities (LSE)	0	0	Laura Nelson
WECC-0115	Idaho Power Company	Electric Generators	0	0	Laura Nelson
WECC-0115	Idaho Power Company	Transmission Owners	0	0	Laura Nelson

WECC

Electric Reliability and Security for the West

Attachment E12

Ballot Pool Results

WECC-0115 BAL-002-WECC-3

Contingency Reserve

Request to Retire R2

Ballot Name: WECC-0115 BAL-002-WECC-2a Contingency Reserve—Retirement of R2

Overview: This project proposed to retire BAL-002-WECC-2a, Requirement R2 on the premise that R2 is redundant to BAL-003-1.1 Frequency Response and Frequency Bias Setting. The drafting team's position is supported by a white paper located on the WECC-0115 project page at the Posted for Comment accordion. A NERC-approved field test examining the potential impact on reliability if R2 is retired was conducted from May 1, 2017, through April 30, 2018.

Ballot Pool Open:	03/11/2019	Ballot Pool Closed:	03/26/2019
Ballot Opened:	03/28/2019	Ballot Closed:	04/11/2019
Total Ballot Pool:	38	Total Votes:	34
Quorum:	89.5%	Weighted Votes:	100%
Ballot Results:	Pass		

Voting Sectors	Total in Ballot Pool	In-Pool Affiliates Excluded	Votes Non-Abstain	Sector Weight	Yes Votes	Weighted Segment Vote	No Votes	Abstain	Total Votes for Quorum	Did Not Vote
Transmission Owners	8		6	0.6	6	60.0%	0	1	7	1
Regional Transmission Organizations (RTO) and Independent System Operators (ISO)	1		1	0.1	1	10.0%	0	0	1	0
Load-Serving Entities (LSE)	10		7	0.7	7	70.0%	0	2	9	1
Transmission Dependent Utilities (TDU)	3		2	0.2	2	20.0%	0	1	3	0
Electric Generators	9		7	0.7	7	70.0%	0	1	8	1
Electricity Brokers, Aggregators, and Marketers	7		6	0.6	6	60.0%	0	0	6	1
Large Electricity End Users	0		0	0	0	0.0%	0	0	0	0
Small Electricity Users	0		0	0	0	0.0%	0	0	0	0
Federal, State, Provincial Regulatory, other Gov. Entities	0		0	0	0	0.0%	0	0	0	0
Regional Entities	0		0	0	0	0.0%	0	0	0	0
Totals	**38**	**0**	**29**	**2.9**	**29**	**100.0%**	**0**	**5**	**34**	**4**

Project	Entity	Segment	Vote	Comment	Name
WECC-0115	British Columbia Hydro & Power Authority	Electric Generators	Abstain	BAL-002-WECC-2 R2 requirement to carry spinning reserves in all hours could provide improved frequency response. The retirement of this requirement may result in Western entities' diminished frequency response performance that may not be alleviated by the current BAL-003-1.1 standard, which is under review and development under NERC Standards Development Project 2017-01. BC Hydro recommends that the retirement of this requirement be coordinated with the revision of the BAL-003-1.1 Frequency Response and Frequency Bias Setting.	Adrian Andreoiu
WECC-0115	British Columbia Hydro & Power Authority	Transmission Dependent Utilities (TDU)	Abstain	BAL-002-WECC-2 R2 requirement to carry spinning reserves in all hours could provide improved frequency response. The retirement of this requirement may result in Western entities' diminished frequency response performance that may not be alleviated by the current BAL-003-1.1 standard, which is under review and development under NERC Standards Development Project 2017-01. BC Hydro recommends that the retirement of this requirement be coordinated with the revision of the BAL-003-1.1 Frequency Response and Frequency Bias Setting.	Adrian Andreoiu

Project	Entity	Segment	Vote	Comment	Name
WECC-0115	British Columbia Hydro & Power Authority	Transmission Owners	Abstain	BAL-002-WECC-2 R2 requirement to carry spinning reserves in all hours could provide improved frequency response. The retirement of this requirement may result in Western entities' diminished frequency response performance that may not be alleviated by the current BAL-003-1.1 standard, which is under review and development under NERC Standards Development Project 2017-01. BC Hydro recommends that the retirement of this requirement be coordinated with the revision of the BAL-003-1.1 Frequency Response and Frequency Bias Setting.	Adrian Andreoiu
WECC-0115	British Columbia Hydro & Power Authority	Load-Serving Entities (LSE)	Abstain	BAL-002-WECC-2 R2 requirement to carry spinning reserves in all hours could provide improved frequency response. The retirement of this requirement may result in Western entities' diminished frequency response performance that may not be alleviated by the current BAL-003-1.1 standard, which is under review and development under NERC Standards Development Project 2017-01. BC Hydro recommends that the retirement of this requirement be coordinated with the revision of the BAL-003-1.1 Frequency Response and Frequency Bias Setting.	Adrian Andreoiu

Project	Entity	Segment	Vote	Comment	Name
WECC-0115	Southern California Edison Company	Load-Serving Entities (LSE)	Abstain	No comments.	Romel Aquino
WECC-0115	Tacoma Power	Transmission Dependent Utilities (TDU)	Yes	0	John Nierenberg
WECC-0115	Seattle City Light	Transmission Dependent Utilities (TDU)	Yes	0	Hao Li
WECC-0115	Tacoma Power	Electric Generators	Yes	0	Karen Hedlund
WECC-0115	Platte River Power Authority	Transmission Owners	Yes	0	Matthew Thompson
WECC-0115	Tacoma Power	Load-Serving Entities (LSE)	Yes	0	Twila Hofer
WECC-0115	Bonneville Power Administration	Transmission Owners	Yes	0	Kammy Rogers-Holliday
WECC-0115	Bonneville Power Administration	Load-Serving Entities (LSE)	Yes	0	Rebecca Berdahl
WECC-0115	Western Area Power Administration	Electricity Brokers, Aggregators, and Marketers	Yes	0	Timothy Vigil
WECC-0115	Bonneville Power Administration	Electricity Brokers, Aggregators, and Marketers	Yes	0	Andrew Meyers
WECC-0115	California Independent System Operator	Regional Transmission Organizations (RTOs) and Independent System Operators (ISO)	Yes	0	Richard Vine

Project	Entity	Segment	Vote	Comment	Name
WECC-0115	Puget Sound Energy, Inc.	Electric Generators	Yes	0	Theresa Rakowsky
WECC-0115	Puget Sound Energy, Inc.	Load-Serving Entities (LSE)	Yes	0	Theresa Rakowsky
WECC-0115	Puget Sound Energy, Inc.	Transmission Owners	Yes	0	Theresa Rakowsky
WECC-0115	Los Angeles Department of Water and Power	Transmission Owners	Yes	0	Pjoy Chua
WECC-0115	Los Angeles Department of Water and Power	Load-Serving Entities (LSE)	Yes	0	Pjoy Chua
WECC-0115	Los Angeles Department of Water and Power	Electricity Brokers, Aggregators, and Marketers	Yes	0	Pjoy Chua
WECC-0115	Los Angeles Department of Water and Power	Electric Generators	Yes	0	Pjoy Chua
WECC-0115	Arizona Public Service Company	Load-Serving Entities (LSE)	Yes	0	Vivian Vo
WECC-0115	Arizona Public Service Company	Electric Generators	Yes	0	Kelsi Rigby
WECC-0115	Arizona Public Service Company	Electricity Brokers, Aggregators, and Marketers	Yes	0	Chinedu Ochonogor
WECC-0115	Arizona Public Service Company	Transmission Owners	Yes	0	Michelle Amarantos
WECC-0115	Public Utility District No. 1 of Chelan County	Electric Generators	Yes	0	Meaghan Connell

Project	Entity	Segment	Vote	Comment	Name
WECC-0115	Public Utility District No. 1 of Chelan County	Transmission Owners	Yes	0	Meaghan Connell
WECC-0115	Public Utility District No. 1 of Chelan County	Load-Serving Entities (LSE)	Yes	0	Meaghan Connell
WECC-0115	Public Utility District No. 1 of Chelan County	Electricity Brokers, Aggregators, and Marketers	Yes	0	Meaghan Connell
WECC-0115	Puget Sound Energy, Inc.	Electric Generators	Yes	0	Eleanor Ewry
WECC-0115	Platte River Power Authority	Load-Serving Entities (LSE)	Yes	0	Jeff Landis
WECC-0115	Platte River Power Authority	Electricity Brokers, Aggregators, and Marketers	Yes	support the retirement of BAL-002-WECC-2a, Requirement R2 on the premise that R2 is redundant to BAL-003-1.1 Frequency Response and Frequency Bias Setting. We are at the end of a 2 year field trial and have found no degradation in reliability in general and also none specific to BAL-002 or BAL-003 performance.	Sabrina Martz
WECC-0115	Platte River Power Authority	Electric Generators	Yes	0	Tyson Archie
WECC-0115	Idaho Power Company	Electricity Brokers, Aggregators, and Marketers	0	0	Laura Nelson
WECC-0115	Idaho Power Company	Load-Serving Entities (LSE)	0	0	Laura Nelson
WECC-0115	Idaho Power Company	Electric Generators	0	0	Laura Nelson

Project	Entity	Segment	Vote	Comment	Name
WECC-0115	Idaho Power Company	Transmission Owners	0	0	Laura Nelson

Electric Reliability and Security for the West

Attachment E13
Posting 1NERC Response to Comments
WECC-0115 BAL-002-WECC-3
Contingency Reserve
Request to Retire R2

Posting 1 NERC Response to Comments

The WECC-0115 BAL-002-WECC-2a,[1] Contingency Reserve Drafting Team (DT) thanks everyone who submitted comments on the proposed document. As all comments were in support of the project, no changes were made.

Posting

NERC posted the project for public comment from June 20, 2019, through August 5, 2019.

NERC distributed notice for the posting on June 20, 2019. NERC asked stakeholders to give feedback on the proposed document through a standardized electronic template. Four sets of responses were received, including comments from four different people from four companies representing five of the industry Segments.

Location of Comments

All comments received on the project can be viewed in their original format on the WECC-0115 project page under the "Submit and Review Comments" accordion.

Contacts and Appeals

If you feel your comment has been omitted or overlooked, please contact W. Shannon Black, WECC Consultant, at (503) 307-5782. In addition, there is a WECC Reliability Standards appeals process.

[1] The naming nomenclature changed during development from BAL-002-WECC-2, BAL-002-WECC-2a, and will change to BAL-002-WECC-3 if approved.

Respondents

Respondent		Organization
1	Aaron Cavanaugh	Bonneville Power Administration
2	Laurie Williams	PNM Resources— Public Service Company of New Mexico
3	Sandra Shaffer	Berkshire Hathaway—PacifiCorp
4	Richard Vine	California Independent System Operator

Index to Questions, Comments, and Responses

Question

1. Do you agree the development of BAL-002-WECC-3 met the "Open" criteria as outlined above? If "No," please explain in the comment area below:
2. Do you agree the development of BAL-002-WECC-3 met the "Inclusive" criteria as outlined above? If "No," please explain in the comment area below:
3. Do you agree the development of BAL-002-WECC-3 met the "Balanced" criteria as outlined above? If "No," please explain in the comment area below:
4. Do you agree the development of BAL-002-WECC-3 met the "Due Process" criteria as outlined above? If "No," please explain in the comment area below:
5. Do you agree the development of BAL-002-WECC-3 met the "Transparent" criteria as outlined above? If "No," please explain in the comment area below:

Comments and Responses

All commenters responded "yes" to all questions asked. No changes were made.

Respondent	Comment
Bonneville Power Administration	Yes
PNM	Yes
Berkshire Hathaway	Yes
California Independent System Operator	Yes

WECC Standards Committee Roster

The following individuals are those assigned to the WECC Standards Committee as of June 18, 2019.

Sunitha Kothapalli, Puget Sound Energy ..... SVS 1 Transmission

Vacant ..... SVS 2 RTO/ISO[1]

Dana Cabbell, Southern California Edison ..... SVS 3 LSE[2]

Marty Hostler, Northern California Power Agency ..... SVS 4 TDU[3]

Gary Nolan, Arizona Public Service ..... SVS 5 Generators

Joe Tarantino, Sacramento Municipal Utility District ..... SVS 6 Broker/Aggregator/Marketers

Caitlin Liotiris, Utah Association of Energy Users ..... SVS 7 Large Electricity End Users

Crystal Musselman, Proven Compliance Solutions ..... SVS 8 Small Electricity Users

Davy Zhuang, British Columbia Utilities Commission ..... SVS 9 Gov. Entities

Steven Rueckert, WECC ..... SVS 10 Regional Entities

James Avery, Chair ..... Non-Affiliated Director

[1] Regional Transmission Organization/Independent System Operator
[2] Load-Serving Entity
[3] Transmission Dependent Utilities

Exhibit F

Drafting Team Roster

Electric Reliability and Security for the West

Exhibit F

Drafting Team Roster

WECC-0115 BAL-002-WECC-3

Contingency Reserve

Request to Retire R2

WECC-0115 Contingency Reserve Drafting Team Roster

On August 12, 2015, the WECC Standards Committee (WSC) appointed the initial WECC-0115 drafting team. Thereafter, the WECC-0115 Field Test was initiated spanning a lengthy period.

On October23, 2018, the WSC adjusted the DT roster adding/deleting drafting team members as indicated in the Candidate column. The action was taken per the WSC Charter, Section WSC Charter, Section 4. Actions Without a Meeting.

On November 27, 2018, the WSC assigned Mr. James Wells to replace Mr. Don Badley as DT chair. That action was taken per the November 27, 2018 Consent Agenda.

Candidate	Experience
Ali Miremadi CAISO	Ali Miremadi is the California Independent System Operator's (CAISO) Senior Operations Policy Advisor. He has been with the CAISO for over 17 years and was part of the CAISO start-up team back in 1997. Mr. Miremadi has held various positions within CAISO including leading the Operator Training program through transition to full compliance with NERC Standard PER-005, and design/oversight of the real time and near miss Root Cause Analysis Process. Mr. Miremadi designed the real-time Operations reliability metrics for daily review of CAISO operator performance. In his current assignment, Mr. Miremadi is responsible for the review and evaluation of North American Electric Reliability Corporation (NERC) proposed standards impacting CAISO Operations. He works directly with CAISO upper management coordinating the formulation of CAISO Operations positions on proposed NERC standards and prepares comments and filings at NERC or other regulatory agencies. Mr. Miremadi began his career at the California Public Utilities Commission (CPUC) where he spent most of his tenure working on investor owned utility Demand-side Management and Load Management programs. He was part of the CPUC team that worked on the restructuring of the electric utility industry.

Candidate	Experience
	Mr. Miremadi has a Bachelor of Science degree in Engineering and a Master of Arts degree in Management. He holds an active NERC System Operator Certification.
Bart McManus Bonneville Power Administration (Added October 23, 2018)	Mr. McManus received his Bachelor of Science degree in Electrical Engineering from the University of Washington and has been at Bonneville Power Authority Administration (BPA) since 1994. Mr. McManus was the lead programmer for the Automatic Generation Control (AGC) system for multiple years then became the lead for AGC and other Balancing Authority Area Operations in BPA. Mr. McManus began working on wind integration issues in 2006 and was team lead for AGC and wind integration for a few years. He is currently the AGC and wind integration subject matter engineer and the wind integration lead for BPA Transmission Operations. Mr. McManus was part of the North American Electric Reliability (NERC) Performance Work group that drafted the original Disturbance Control Performance Standard and was also on the drafting team for the original WECC regional Reliability Standard addressing reserves.
David Frederick Salt River Project (Inactive October 23, 2018)	Mr. Frederick served as the drafting team chair for WECC-0114 BAL-002-WECC-2, Contingency Reserve, Request for Interpretation Drafting Team and was a member of the WECC-0103 BAL-STD-002-0, Operating Reserves Drafting Team and the WECC-0083 BAL-002-WECC-1, Contingency Reserves Drafting Team. Mr. Frederick is a Cost/Plant/Power Production Analyst for Salt River Project. He has worked in merchant and reliability areas at SRP since 1999. Previously, he served as the Administrator of the Southwest Reserve Sharing Group. Mr. Frederick is a NERC-Certified Dispatcher in Balancing, Interchange, and Transmission Operations and holds a Bachelor of Science degree in Accountancy.
David Kirsch, Bonneville Power Administration (Inactive as of October 23, 2018)	Mr. Kirsch has 27 years of experience in the electric utility industry. He began his career in 1988 at PacifiCorp, in the Major Equipment Specifications, and Substation Design groups, which led to a Distribution Engineer position in PacifiCorp's Portland district. Mr. Kirsch joined BPA's workforce in 2001 as a Field Engineer in the Substation Protection and Control (SPC) group leading to assignment as an SPC District Engineer. In 2009, Mr. Kirsch transitioned to BPA's Transmission Technical Operations organization in the AGC workgroup where he served as part of the maintenance committee with the United States Army Corps of Engineers and the United States Bureau of Reclamation. In 2014, Mr. Kirsch was named Chair of the Technical Operations and Implementation

Candidate	Experience
	Subcommittee (TOIS) which coordinates controls and signals with for hydro projects. Mr. Kirsch is BPA's subject matter expert for several NERC Standards, including BAL-002-WECC-2, Contingency Reserve and is a member WECC's Performance Work Group.
Don Badley Northwest Power Pool (Inactive October 23, 2018 - Retired)	The following is a listing of Mr. Don Badley's experience related to NERC and WECC BAL standards: • Groups served on (past and present): North American Power Systems Interconnection Committee (NAPSIC) Performance Subcommittee, WECC Control Work Group, WECC Operating Practices Subcommittee, WECC Technical Operations Subcommittee, WECC Reserve Issues Task Force, NERC Functional Model Task Force, NERC Resources Subcommittee, NERC Frequency Task Force, NERC Frequency Responsive Reserve Standard Drafting Team, Reserve Task Force, and WECC Performance Work Group. • Groups chaired (past and present): NAPSIC Performance Subcommittee, WECC Performance Work Group, WECC Reserve Issues Task Force, NERC Control Criteria Task Force, NERC Resources Subcommittee. • Mr. Badley served on and chaired multiple groups within the Northwest Power Pool related to the BALs. Employment History Mr. Badley started working for Pacific Power & Light in 1963 and began his career with the Northwest Power Pool in 1975. Professional history Mr. Badley was affiliated with the IEEE and served in multiple positions including Oregon Section Chair and twice as the Northwest Area Chair (Alaska, Oregon, and Washington). Mr. Badley is a life member of IEEE.
James Wells Los Angeles Department of Water and Power (LADWP)	Mr. Wells has a Bachelor of Science and a Master of Science in Electrical Engineering from the University of Southern California, and is a licensed Professional Electrical Engineer in the State of California. Mr. Wells has nine years of utility work experience at Los Angeles Department of Water and Power, serving the first three years in Energy Reconciliation/After-the-Fact supporting developing and maintaining custom reporting tools and

Candidate	Experience
(Appointed chair on November 27, 2018.)	database applications for energy scheduling, marketing transactions, interchange control, transmission utilization, and loss accounting. Mr. Wells served six years in Operating Engineering/Grid Operations Support providing outage coordination support by facilitating and studying complex outages and providing real-time power system analysis in support of unplanned or abnormal system conditions. Mr. Wells serves as a technical engineering operations expert providing guidance and direction to multiple internal and external stakeholders on power system operation issues. Mr. Wells is the LADWP representative on multiple regional study groups including the Operating Study Subcommittee and the Pacific Southwest Interconnection Reliability Operating Limit Study group. Mr. Wells is a member of the WECC Performance Work group and is the author of the WECC-0115 Standards Authorization Request. .
Ken Otto Western Area Power Administration, Golden, and Loveland, CO (Inactive October 23, 2018 - Retired)	Mr. Ken Otto began his Federal career as a student engineer with Bonneville Power Administration in 1980, before joining Western Area Power Administration (WAPA) as a system protection engineer in 1983. Many of the policies and procedures he implemented during his tenure as the lead electrical engineer became standard WAPA policy. These include substation computerized controls, an electronic relay replacement program and collaboration with the Supervisory Controls and Data Acquisition Division to develop Supervisory Control And Data Acquisition standards. Mr. Otto was involved with the installation and commissioning of phase shifting transformers on the TOT2A Project, and the Kayenta Series Capacitor Project. When he accepted last position in the Colorado River Storage Project Management Center in October 2000, Mr. Otto took charge over the office's real-time merchant activities. Mr. Otto was instrumental in successfully integrating the Loveland Area Projects and Basin Electric merchant activities into the Energy Management & Marketing Office (Hoover). Mr. Otto developed software tools and procedures for scheduling and marketing WAPA's resources. Mr. Otto's last position was that of Supervisory Energy Management and Marketing specialist at Western's Energy Management and Marketing Office, in Montrose, Colorado. Mr. Otto serves on the WECC Operating Committee, and both the Seams Issues Subcommittee and Market Issues Subcommittee as well as various other subcommittees, task forces and drafting teams. Mr. Otto also represents Western

Candidate	Experience
	on the Western Systems Power Pool (WSPP) Executive Committee and Operating Committee. Mr. Otto received his Bachelor of Science degree in Electrical Engineering from the University of New Mexico and is a registered professional engineer.
Rick Lowther Salt River Project	Mr. Lowther has 38 years of experience in the electric utility Industry. He began his career at Houston Light & Power as a system planning engineer. Mr. Lowther spent 14 years working for an Energy Management System vendor. There, Mr. Lowther developed EMS applications and managed developers responsible for EMS applications such as Automatic Generation control (AGC), Interchange Scheduling, Thermal Unit Commitment, State Estimation, Optimal Power Flow and Contingency Analysis. For the last 19 years, Mr. Lowther has worked for Salt River Project (SRP). Initially, he led a team that provided EMS support and developed operational support applications. He was the lead designer and developer of the Southwest Reserve Sharing Group's first reserve sharing system and the Southwest Open Access Same-Time Information System site that was used by eight desert southwest utilities for transmission access sales until 2004. He was also the lead designer and developer of SRP's current interchange scheduling and accounting system. For the last seven years, Mr. Lowther worked in SRP's Balancing Authority and Transmission Operations area. In that role, he provides engineering support and training for generation and transmission dispatchers. He is currently SRP's subject matter expert for most NERC BAL and INT Standards and well as some TOP Standards. Mr. Lowther participates in several WECC subcommittees (Interchange Scheduling and Accounting Subcommittee), work groups (Performance Work Group (PWG), Electronic Scheduling Work Group, Data Exchange Work Group, EMS Work Group), and task forces (Unscheduled Flow Event Analysis Task Force). He currently chairs the PWG. Mr. Lowther received a Bachelor of Science in Electrical Engineering degree from the University of Houston.
Robert Johnson Rocky Mountain	Mr. Johnson served as the Rocky Mountain Reserve Group (RMRG) Administrator for more than 15 years, 20 plus years as Senior Engineer for WECC Members (PSColorado, WAPA), Member of numerous WECC and NERC

Candidate	Experience
Reserve Sharing Group	technical committees over my career. Presently the WECC Operating Committee (Transmission) representative for PSColorado/Xcel. Also, on the Operating Issues Work Group. Mr. Johnson has served on several drafting teams and is presently on the TOP-007 retirement team. Mr. Johnson has served as administrator for the Rocky Mountain Reserve Group and Senior Operations Engineer for PSCo from 1998 to present. He manages the generation reserve coordination, compliance monitoring and reporting, software development, and training for the Rocky Mountain Reserve Group and is involved in all aspects of administering the RMRG—10 Members covering Colorado and Wyoming. As senior Engineer for PSCo prepare advanced operational analysis to address operational issues and concerns covering a broad spectrum. Mr. Johnson is a voting Member of the: • WECC Operations Committee (OC) Colorado Coordinated Planning Group • WECC Operating Procedures Review Group, Foothills Planning Group • Rocky Mountain Operations Study Group. Mr. Johnson was previously a part of the NERC Compliance and Certification Committee, WECC Operating Capability Studies Group and NERC Standards Compliance Task Force. Over the course of his career, he has drafted multiple technical papers for the Institute of Electrical and Electronics Engineers. Manager and Supervisor in Resource and Transmission Planning; 1988-1998 Western Area Power Administration, Golden, and Loveland, CO Managed the operational, resource and transmission planning group for Western's RMR Region in the States of Colorado, Wyoming, and portions of Utah, New Mexico, Nebraska, and Montana and in a separate position supervised planning engineers evaluating projects for all of Western's Regions. Served on the NERC Planning Committee and numerous WECC technical committees.

Candidate	Experience
	Mr. Johnson served as Power System Engineer for the Bureau of Reclamation and Western Area Power (1971-1988) where he was involved in a wide variety of technical assignments.
John Tolo Tucson Electric Power	Mr. Tolo is currently employed by Tucson Electric Power as the director of system control and reliability. He has been in the utility business for 26 years. Mr. Tolo has held positions in power production and distribution, transmission, and generation operations. He has memberships in the NERC Resources Subcommittee, the WECC Performance Work Group, serves as vice chair of the WECC Operating Committee, chair of the WECC Joint Guidance Committee, and is a member of the BAL-004-WECC-01 and WECC-0068 BAL-004-WECC-02, Automatic Time Error Correction (ATEC) Drafting Team.

Exhibit G

VRF and VSL Justification

Electric Reliability and Security for the West

Exhibit G

VRF and VSL Justification

WECC-0115 BAL-002-WECC-3

Contingency Reserve

Request to Retire R2

Violation Risk Factors & Violation Severity Levels

Violation Risk Factors and Violation Severity Levels were previously approved by FERC. No changes are proposed other than updating the format of the associated components.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

August 16, 2019

FEDERAL ENERGY REGULATORY COMMISSION
Office of Electric Reliability
Division of Compliance

Docket No. RC11-6
NOTICE OF COMPLETION OF NERC ANNUAL REVIEW OF FFT AND COMPLIANCE EXCEPTION PROGRAMS

Loye Hull:

The staff of the North American Electric Reliability Corporation (NERC) coordinated with Commission staff to conduct the annual oversight of the Find, Fix, Track and Report (FFT) program, as outlined in the March 15, 2012 Order,[1] and the Compliance Exception (CE) program, as proposed by NERC's September 18, 2015 annual Compliance Filing.[2] NERC and Commission staff agreed to exclude the Florida Reliability Coordinating Council (FRCC) from the survey, reducing the burden on FRCC as it focused efforts on a planned and approved termination of its responsibilities as a Regional Entity. NERC and Commission staff reviewed a sample of 27 FFT possible violations out of 47 FFT possible violations posted by NERC between October 2017 and September 2018 and a sample of 37 CE instances of noncompliance out of 898 CE instances of noncompliance posted by NERC between October 2017 and September 2018.

NERC staff believes that the FFT and CE programs are meeting expectations. Sampling for the 2018 program year indicated that the Regional Entities appropriately included all sampled possible violations (100 percent) in the FFT and CE programs and that all of the possible violations have been adequately remediated, with the exception of remaining issues with ongoing mitigation which will be remediated once the mitigation is completed. NERC noted the continued improvement in the quality of issues that were posted with a decreasing number of documentation concerns. Specifically, the identification of root cause and risk statements in FFTs and CEs has improved significantly over the past several years. NERC also noted ongoing improvement in the clear identification of factors affecting the

[1] *North American Electric Reliability Corp.*, 138 FERC ¶ 61,193, at P 73 (2012) (discussing Commission plans to survey a random sample of FFTs submitted each year to gather information on how the FFT program is working).

[2] *North American Electric Reliability Corp.*, Docket No. RC11-6-004, at 1 (Nov. 13, 2015) (delegated letter order) (stating "NERC's intention to combine the evaluation of Compliance Exceptions with the annual sampling of FFTs to further streamline oversight of the FFT and compliance exception programs").

risk prior to mitigation, as well as actual harm, which was identified in all samples. In addition, the FFTs and CEs sampled did not contain any material misrepresentations by the registered entities.

Based on these findings, NERC Enforcement staff concluded that the Regional Entities properly execute FFTs and Compliance Exceptions.

Sincerely,

Simran Ahuja
Enforcement Advisor

Ed Kichline
Senior Counsel and Director of Enforcement Oversight

cc: Parties in Docket No. RC11-6

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC	**)**	**Docket No. RR10-1-000**
RELIABILITY CORPORATION	**)**	**Docket No. RR13-3-000**

ANNUAL REPORT OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION ON WIDE-AREA ANALYSIS OF TECHNICAL FEASIBILITY EXCEPTIONS

The North American Electric Reliability Corporation ("NERC") hereby provides the 2019 Annual Report on Wide-Area Analysis of Technical Feasibility Exceptions (the "2019 Annual Report") in compliance with Paragraphs 220 and 221 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Order No. 706[1] and Appendix 4D of the NERC Rules of Procedure ("ROP"). The 2019 Annual Report covers the period from July 1, 2018 through June 30, 2019.

I. BACKGROUND

In Order No. 706, FERC approved eight Critical Infrastructure Protection ("CIP") Reliability Standards and, among other things, directed NERC to develop a set of conditions or criteria that a registered entity must follow to obtain a Technical Feasibility Exception ("TFE") from specific requirements in the CIP Reliability Standards.[2] The Commission stated that the TFE process must include: mitigation steps, a remediation plan, a timeline for eliminating the use of the TFE unless the registered entity provides appropriate justification, regular review of the

[1] *Mandatory Reliability Standards for Critical Infrastructure Protection*, 122 FERC ¶ 61,040 (2008) ("Order No. 706").
[2] *Id.* at P 178.

continued need for the TFE, internal approval by senior managers, and regional approval through the Electric Reliability Organization ("ERO").[3]

Order No. 706 also required that NERC submit an annual report to the Commission that provides a wide-area analysis of the use of TFEs and their effect on Bulk-Power System reliability. The Commission stated:

> The annual report must address, at a minimum, the frequency of the use of such provisions, the circumstances or justifications that prompt their use, the interim mitigation measures used to address vulnerabilities, and efforts to eliminate future reliance on the exception…. [T]he report should contain aggregated data with sufficient detail for the Commission to understand the frequency with which specific provisions are being invoked as well as high level data regarding mitigation and remediation plans over time and by region.[4]

In October 2009, NERC filed amendments to its ROP to implement the Commission's directive in Order No. 706, proposing Section 412 (Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards)[5] and Appendix 4D (Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards). On January 21, 2010, the Commission approved NERC's amended ROP.[6]

On April 8, 2013, NERC filed revisions to Appendix 4D of the ROP to streamline the TFE approval process, reflecting NERC, Regional Entity, and industry experience processing TFE

3 *Id*. at P 222.

4 *Id*. at PP 220-21.

5 Section 411 in the currently effective ROP (January 2019).

6 *N. Am. Elec. Reliability Corp.*, 130 FERC ¶ 61,050 (2010) ("January 21 Order"), *order on compliance*, 133 FERC ¶ 61,008 (2010) ("October 1 Order"), *order on reh'g*, 133 FERC ¶ 61,209 (2010), *order on compliance*, 135 FERC ¶ 61,026 (2011) ("April 12 Order"). The Commission requested further information and clarification regarding certain aspects of the TFE process. On April 21, 2010, NERC submitted its compliance filing in response to the January 21 Order. On October 1, 2010, the Commission issued an order accepting NERC's April 2010 filing as partially compliant and directing further changes to the TFE Procedure. *See* October 1 Order. On December 23, 2010, NERC submitted a compliance filing in response to the Commission's October 1 Order, which the Commission subsequently accepted. *See* April 12 Order.

requests since the inception of the program. On September 3, 2013, FERC approved the proposed revisions and directed limited revisions to Appendix 4D, including modifications to: (1) specify a time frame for reporting Material Changes to TFEs upon identification and discovery; and (2) require the annual TFE report to include information on Material Change Reports and TFE expiration dates.[7] NERC submitted a compliance filing consistent with the directives from the September 2013 Order, which the Commission approved on January 30, 2014.[8] Sections 11.2.4 and 13 of Appendix 4D set forth the requirements for the annual TFE report, as modified in accordance with the September 2013 Order.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to:

Lauren A. Perotti
Senior Counsel
North American Electric Reliability Corporation
1325 G St., N.W., Suite 600
Washington, D.C. 20005
202-400-3000
lauren.perotti@nerc.net

Daniel Bogle
Senior CIP Assurance Advisor
North American Electric Reliability Corporation
3353 Peachtree Road NE, Suite 600 – North Tower
Atlanta GA 30326
404-446-9605
daniel.bogle@nerc.net

III. 2019 ANNUAL REPORT

This section provides the TFE information required by Appendix 4D of the ROP. In accordance with Appendix 4D, NERC prepared the 2019 Annual Report in consultation with the Regional Entities. The Regional Entities provided regular reports to NERC regarding the types of Covered Assets for which the Regional Entities have approved TFEs.[9] In addition, each Regional Entity provided information on the elements identified in Section 13 of Appendix 4D to be

[7] *N. Am. Elec. Reliability Corp.*, 144 FERC ¶ 61,180 at PP 14, 17-18 (2013) ("September 2013 Order").
[8] *N. Am. Elec. Reliability Corp.*, Docket No. RR13-3-001 (Jan. 30, 2014) (delegated letter order).
[9] Appendix 2 of the ROP defines the term "Covered Asset" as "any BES Cyber Asset, BES Cyber System, Protected Cyber Asset, Electronic Access Control or Monitoring System, or Physical Access Control System that is subject to" a TFE.

included in the 2019 Annual Report. NERC compiled and analyzed the TFE data provided by the Regional Entities in preparation for the 2019 Annual Report. In preparing the 2019 Annual Report, NERC identified errors in certain TFE data reported for 2018. The correct data is reported below. NERC has implemented additional controls to ensure that data reported for 2019 and in future years is complete and accurate.

The 2019 Annual Report is the last annual report that will depict TFE data for Florida Reliability Coordinating Council ("FRCC"). The dissolution of FRCC resulted in the transition of 35 registered entities to SERC Reliability Corporation ("SERC"). SERC is responsible for maintaining TFE information for the registered entities transitioning into its region, and its annual report incorporated the transitioning entity's TFE information.

The transition to the CIP cybersecurity Reliability Standards approved in Order No. 791,[10] commonly referred to as the CIP version 5 standards, resulted in a significant decrease to the number of TFEs. As a result, the Regional Entities have been able to better evaluate the risk and impact of TFEs, and gain a better understanding of the value of the TFE process compared to the administrative burden it places on registered entities and Regional Entities. As discussed below, NERC is considering alternatives to the current TFE process to reduce that burden.

IV. Corrections to 2018 Annual Report

In the course of preparing the 2019 Annual Report, NERC identified several errors in some of the data reported in the 2018 Report.[11] NERC identified that the numbers of registered entities

[10] *Version 5 Critical Infrastructure Protection Reliability Standards*, 145 FERC ¶ 61,160 (2013) ("Order No. 791"), *order on clarification and reh'g*, 146 FERC ¶ 61,188 (2014).

[11] *North American Electric Reliability Corporation 2018 Annual Report of the Wide Area Analysis of Technical Feasibility Exceptions*, Docket Nos. RR10-1-000 and RR13-3-000 (filed Sep. 28, 2018).

reported for 2018 reflected only that activity for the 2018 reporting year, and not all approved TFEs. The correct numbers are:

- WECC had a total of 35 registered entities with approved TFEs in 2018;[12]
- NPCC had a total of 14 registered entities with approved TFEs in 2018;[13]
- Texas RE had a total of 12 registered entities with approved TFEs in 2018;[14]
- RF had a total of 13 registered entities with TFE activity in 2018;[15] and
- Across the ERO Enterprise, 120 registered entities had approved TFEs in 2018, not 77 as originally reported.

In light of the importance of having accurate TFE data to NERC's reporting and analysis, NERC's TFE Task Force implemented additional measures in 2019 to help ensure that data submitted and reported is accurate and complete. These measures include additional review processes of raw data.

V. Summary of 2019 TFE Data

The following is the summary of the TFE data reported by each Regional Entity for the elements identified in Section 13.1 of Appendix 4D:[16]

1. Frequency of use of the TFE Request process

The frequency of use of the TFE Request process, disaggregated by Regional Entity and in the aggregate for the United States and for the jurisdictions of other Applicable Governmental Authorities, including (A) the numbers of TFE Requests that have been submitted and approved/disapproved during the preceding year and

[12] NERC originally reported that WECC had nine registered entities with approved TFEs in 2018. *See* 2018 Report at 7.
[13] NERC originally reported that NPCC had six registered entities with approved TFEs in 2018. *See* 2018 Report at 7.
[14] NERC originally reported that Texas RE had three registered entities with approved TFEs in 2018. *See* 2018 Report at 7.
[15] NERC originally reported that RF had 27 registered entities with approved TFEs in 2018. *See* 2018 Report at 8.
[16] Unless stated otherwise, a table or reference to "2019" refers to the reporting period for this report: July 1, 2018–June 30, 2019.

cumulatively since the effective date of this Appendix, (B) the numbers of unique Covered Assets for which TFEs have been approved, (C) the numbers of approved TFEs that are still in effect as of on or about the date of the Annual Report; (D) the numbers of approved TFEs that reached their TFE Expiration Dates or were terminated during the preceding year; and (E) the numbers of approved TFEs that are scheduled to reach their TFE Expiration Dates during the ensuing year.

The data from this reporting period indicates that the number of registered entities that are engaging in the TFE program has stabilized. **Figure 1** shows a breakdown of the number of registered entities with approved TFEs within each Region.

Figure 1: Number of registered entities within each Region with approved TFEs as of 6/30/2019

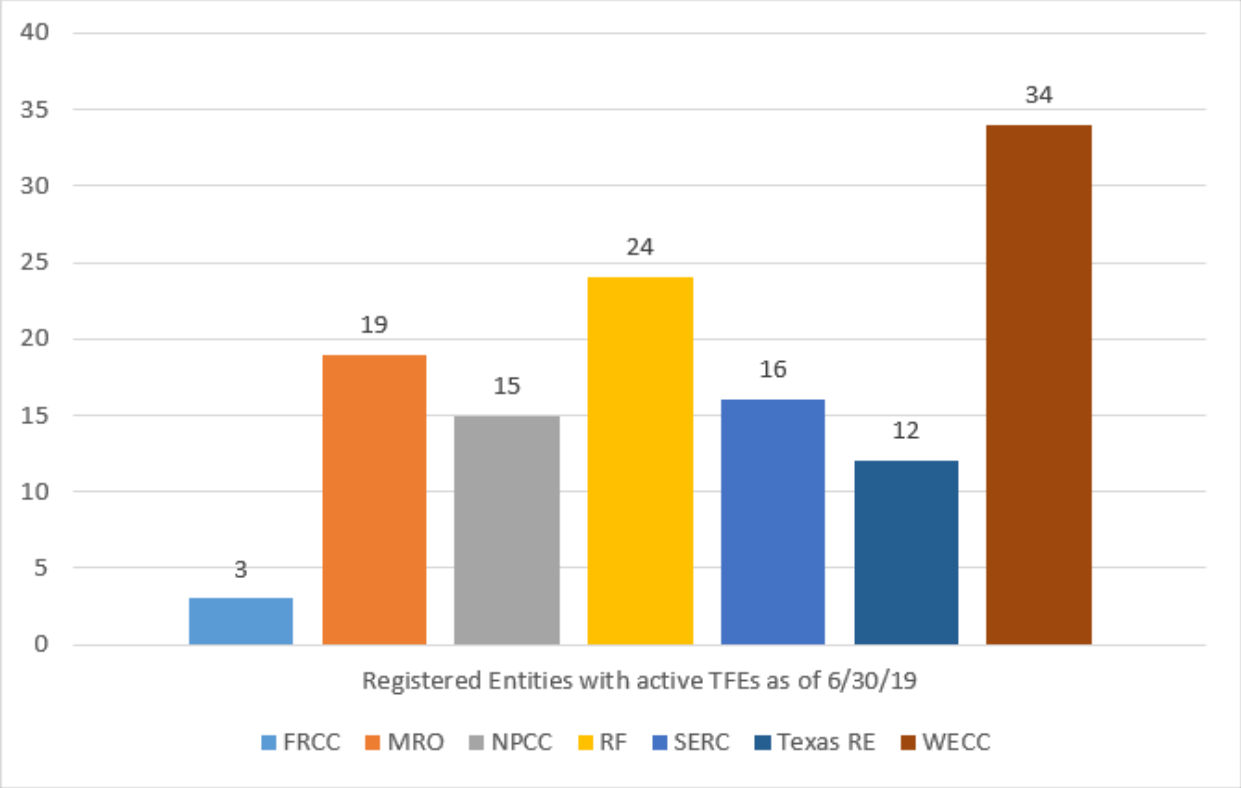


Figure 2 provides a timeframe of registered entities with approved TFEs. This chart shows how many TFEs each region had for the last two reporting periods and this current report period. Utilizing the corrected numbers for WECC, NPCC, and Texas RE (*see* Section IV, above), the number of registered entities with approved TFEs increased modestly from 120 registered entities

in 2018 to 123 registered entities in 2019. This year-over-year stabilization in the number of registered entities with approved TFEs may have been influenced by increases in consolidated registrations and mergers of registered entities.

Figure 2: Three Year Trend of Registered Entities with Approved TFEs

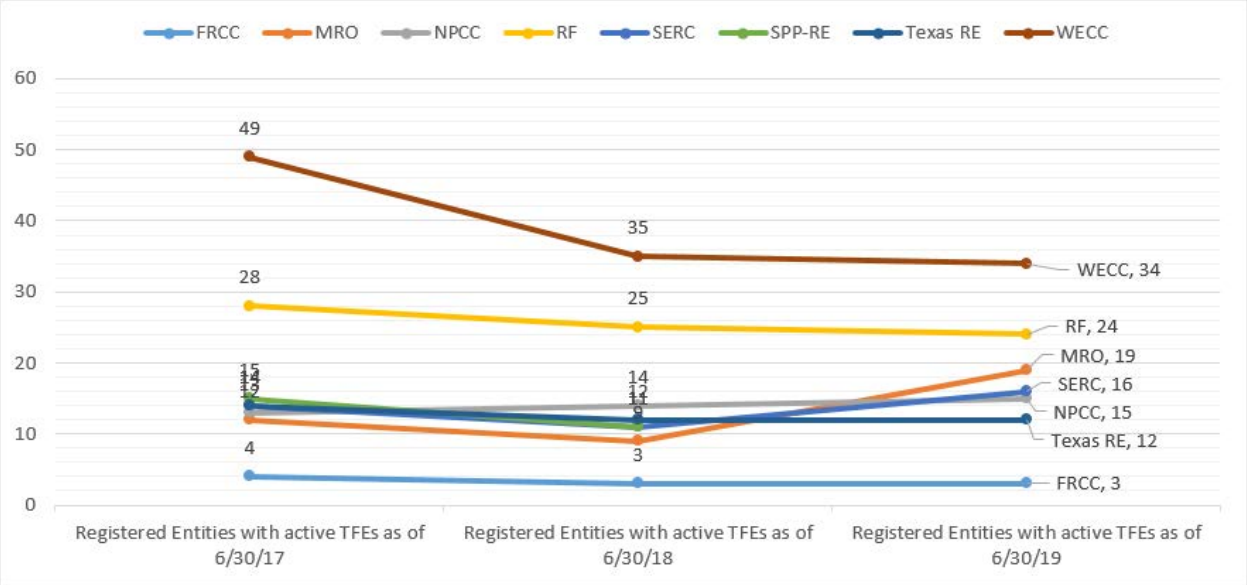


Figure 3 provides data on the use of the TFE program. The first column of **Figure 3** shows the number of registered entities subject to the CIP Reliability Standards. The CIP Reliability Standards apply to the registered entities designated in Applicability Section 4.1 of CIP-002-5 through CIP-014-2 (e.g., Balancing Authority, certain Distribution Providers, etc.). From an industry-wide perspective, the number of "CIP applicable" entities in the U.S. (i.e., with registrations to which the CIP Reliability Standards apply) has increased by just over two percent since last year's report, from 1442 to 1475.

The second column of **Figure 3** depicts the number of CIP applicable registered entities (i.e., those listed in the first column) that report having high or medium impact BES Cyber Systems

("BCS").[17] In 2017, 594 registered entities claimed to have systems that meet that criteria; in 2018, that number decreased nearly 40% to 365. Consolidation of entity registration and Multi-Regional Registered Entities contributed to the decrease. For the 2019 report period, the number increased slightly, less than two percent, to 372 registered entities claiming high or medium impact BCS.

The third column of **Figure 3** shows the number of registered entities with high or medium impact BCS (i.e., those listed in the second column) that have approved TFEs. Using the corrected numbers for 2018, 33 percent of entities claiming high or medium impact BCS had an approved TFE. That percentage stayed the same for 2019.

Figure 3: Frequency of Use (7/1/2018 to 6/30/2019) [18]

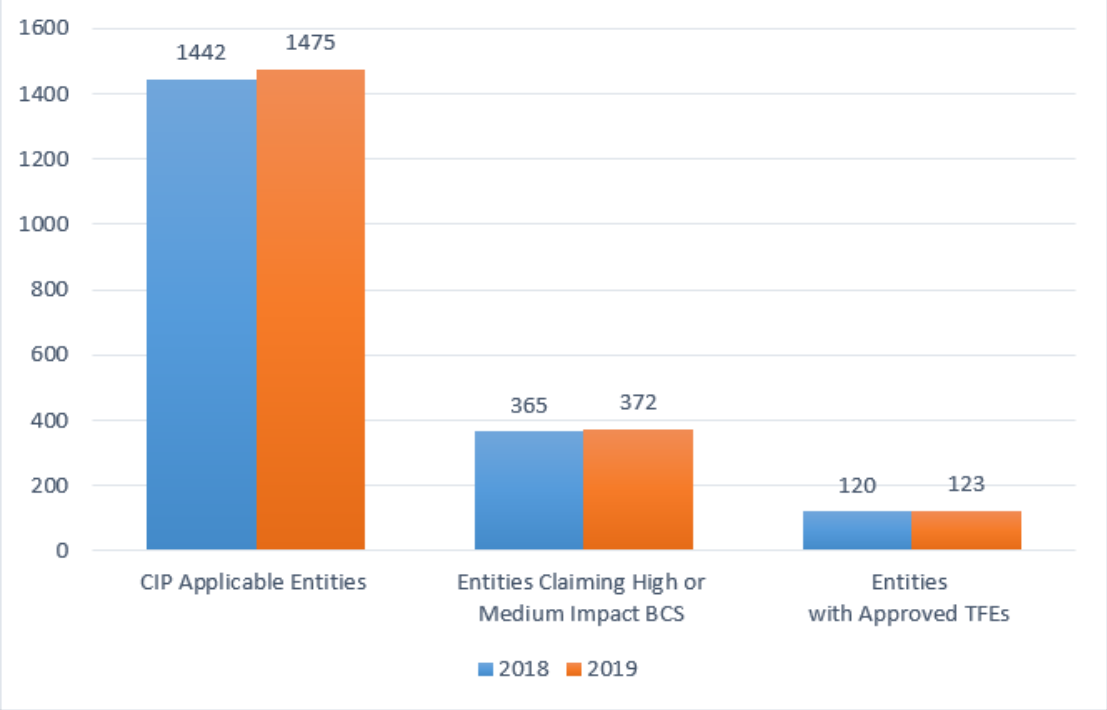


Figure 4 depicts the percentage of registered entities with TFE activity (e.g., submissions of new requests or amendments, terminations, etc.) with the number of registered entities that are

[17] During the reporting period, only requirements applicable to high and medium impact BCS were subject to TFEs.

[18] This figure includes the corrected number of 112 Registered Entities with Approved TFEs from 2018.

subject to the CIP Reliability Standards for the 2018 and 2019 report years. As shown below, the percentage of TFE activity has decreased significantly, from a total of 94 entities with TFE activity in 2018 to 35 entities with TFE activity in 2019. Stated differently, three and a half percent of registered entities that are subject to compliance with the CIP Reliability Standards had some type of activity with TFEs in 2019, compared to seven and a half percent in 2018. MRO believes the decrease for its region is due to the merger of SPP-RE registered entities without much increase of registered entity TFE activity. WECC believes the drop for its region is due to registered entities' CIP programs maturing along with the registered entities undergoing their first full CIP version 5 Standard compliance audits.

Figure 4: TFE Activities, per Number of Applicable Registered Entities

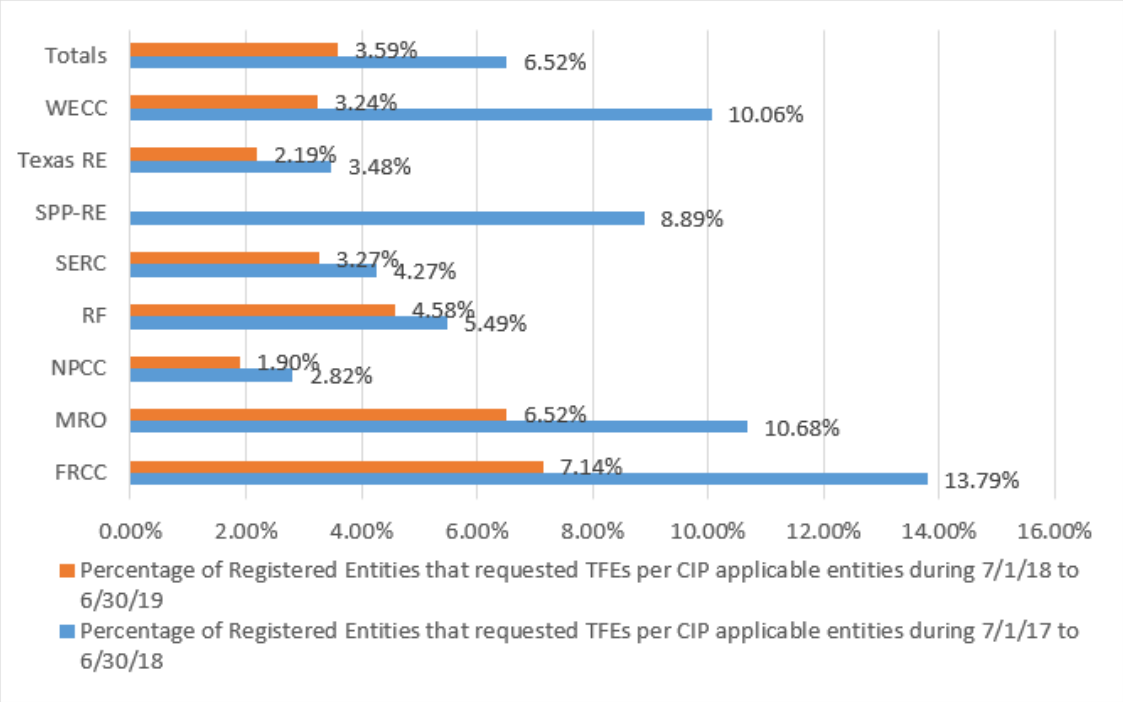


Figure 5 depicts TFE activity by comparing the number of TFE "transactions" (submittals, modifications, terminations, etc.) to the number of registered entities with high or medium impact BES Cyber Systems. The 2018 TFE report showed that, across the ERO Enterprise, almost 30

percent of registered entities that claim high or medium impact BES Cyber Systems had TFE activity.

In 2019, the overall average of entities with high and medium impact BES Cyber Systems that had TFE activity dropped to almost 14 percent. The decrease of activity versus registered entities claiming high or medium impact BES Cyber Systems is due to almost all registered entities having completed their first CIP version 5 audit and the anticipation of the new NERC Align[19] tool. **Figure 5** illustrates the imbalance of TFE activity among Regional Entities; the ERO Enterprise TFE Task Force observes that the effort to maintain and manage TFEs has not leveled off, and in fact continues to be overly burdensome. TFE record-keeping, as currently required in Appendix 4D of the NERC ROP, is burdensome for the Regional Entities and registered entities alike, creating work efforts that may outweigh any perceived benefit to reliability and security. TFE mitigation efforts are being reviewed onsite as Regional Entities sample and assess devices during compliance monitoring engagements.

[19] The Align Project, formerly known as the CMEP Technology Project, is a culmination of strategic efforts that began in 2014 with the goal of improving and standardizing processes across the ERO Enterprise. As the ERO Enterprise matures to use a risk-based approach to its regulatory posture for the CMEP, the need to develop a more comprehensive system to manage and analyze information is more acute. The Align tool roll out has been delayed till the first or second quarter 2020. More on the Align Project can be found here: https://www.nerc.com/ResourceCenter/Pages/CMEPTechnologyProject.aspx.

Figure 5: TFE Activity Compared to the Number of Registered Entities with High or Medium Impact BES Cyber Systems

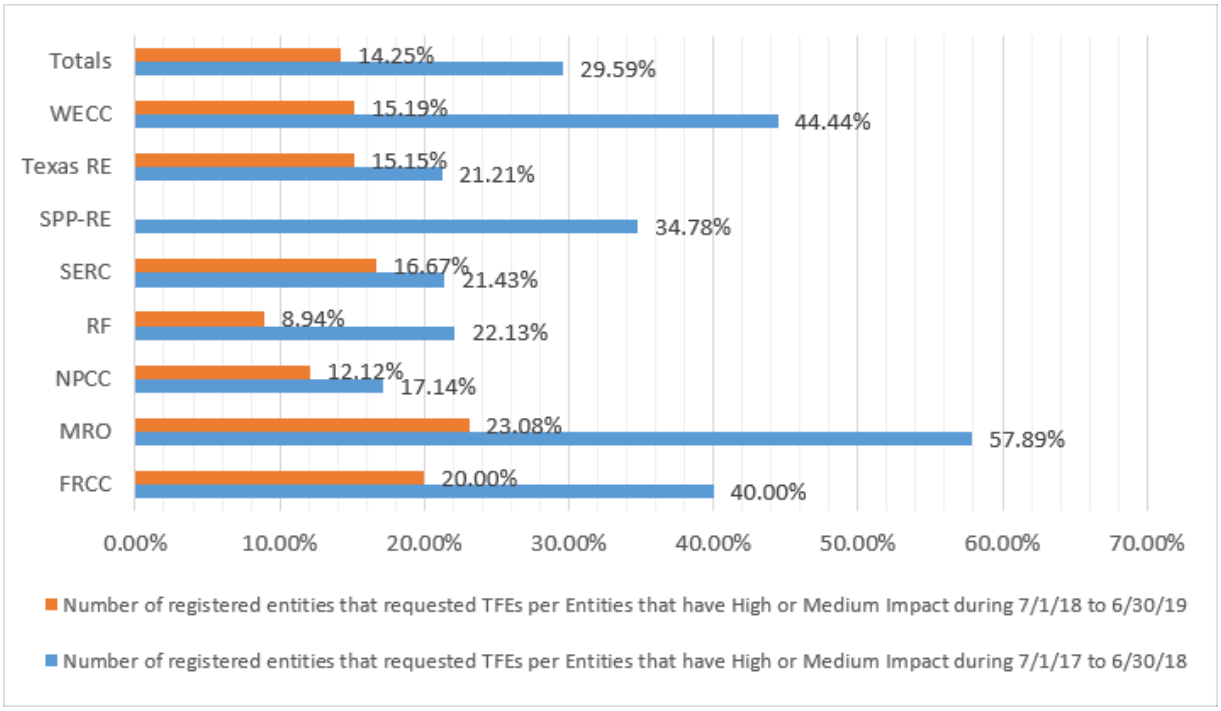


Figure 6 depicts the percentage of registered entities with TFE program activity, compared to the number of registered entities with approved TFEs. This percentage has dropped significantly due to various factors. First, a number of registered entities have consolidated registration for themselves and their affiliates. Second, several Multi-Region Registered Entities had consolidated their TFEs in previous years and may therefore not have any TFE activity this year. SPP RE is included in the report to show a correlation between the activity of the registered entities that were under SPP RE and the subsequent dissemination of the registered entities to MRO and the SERC regions. MRO and SERC both showed significant decreases in TFE activity, even with the absorption of registered entities from the former SPP RE.

Figure 6: Percentage of TFE Interaction per Approved TFEs

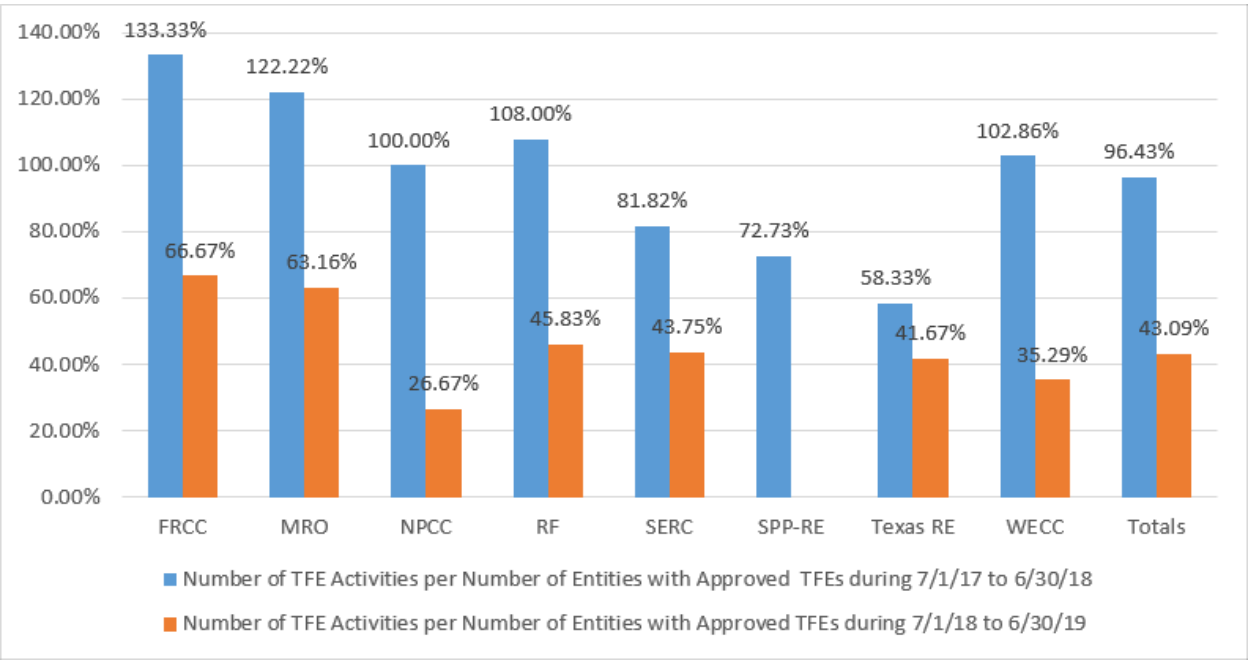


Figure 7 depicts the percentage of registered entities with TFE program activity, compared to the number of total approved TFEs. **Figure 7** uses the corrected data from 2018 as a comparison to 2019 data. The average percentage of approved TFEs having some type of activity has dropped significantly. Only a few Regional Entities have remained relatively the same throughout a two year overview.

Figure 7: Percentage of TFE Program Activity Correlated with Total Approved TFEs

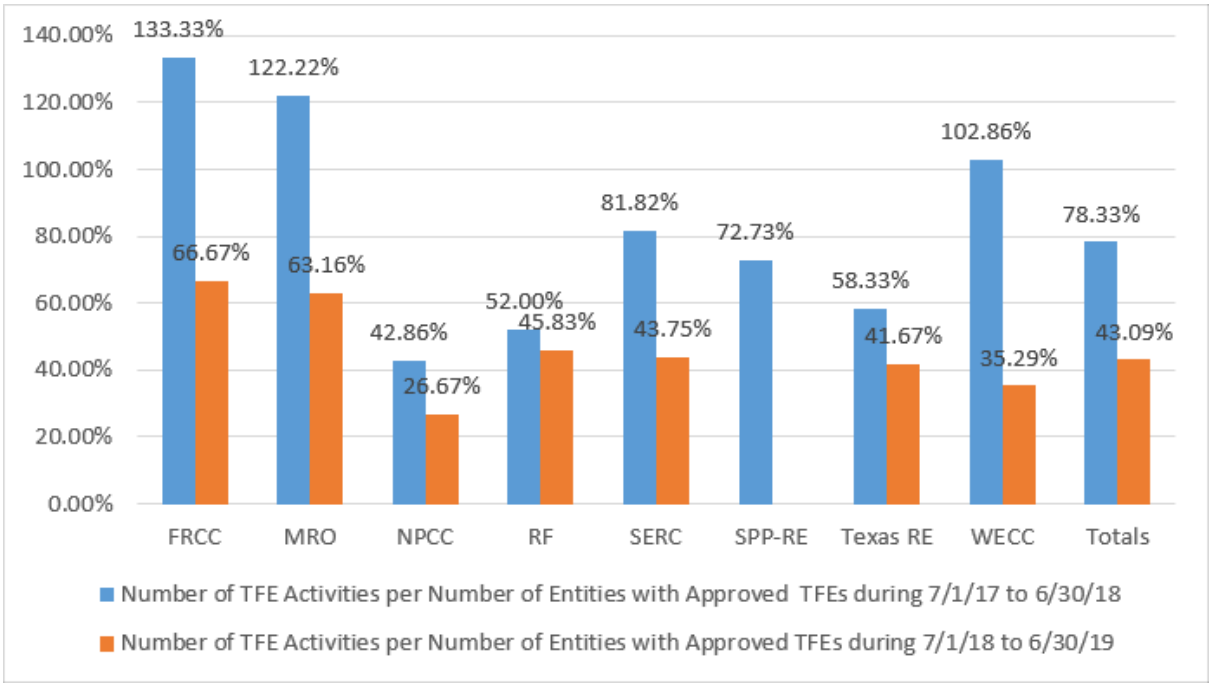
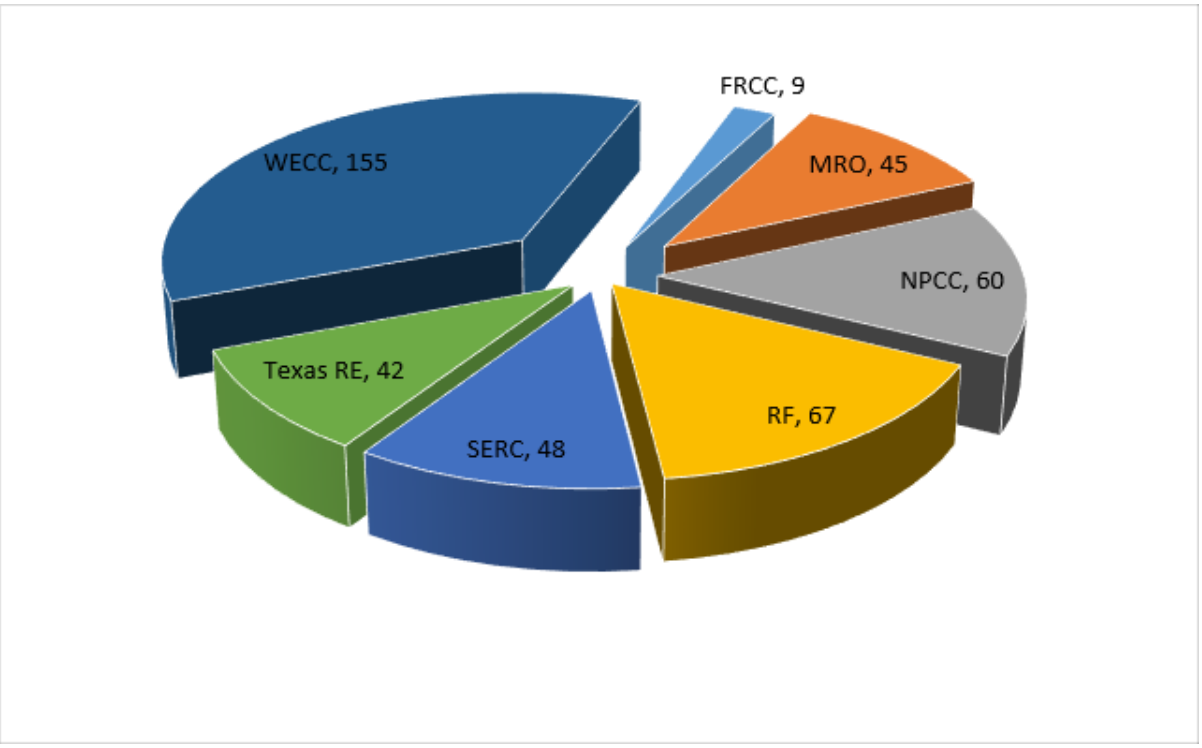


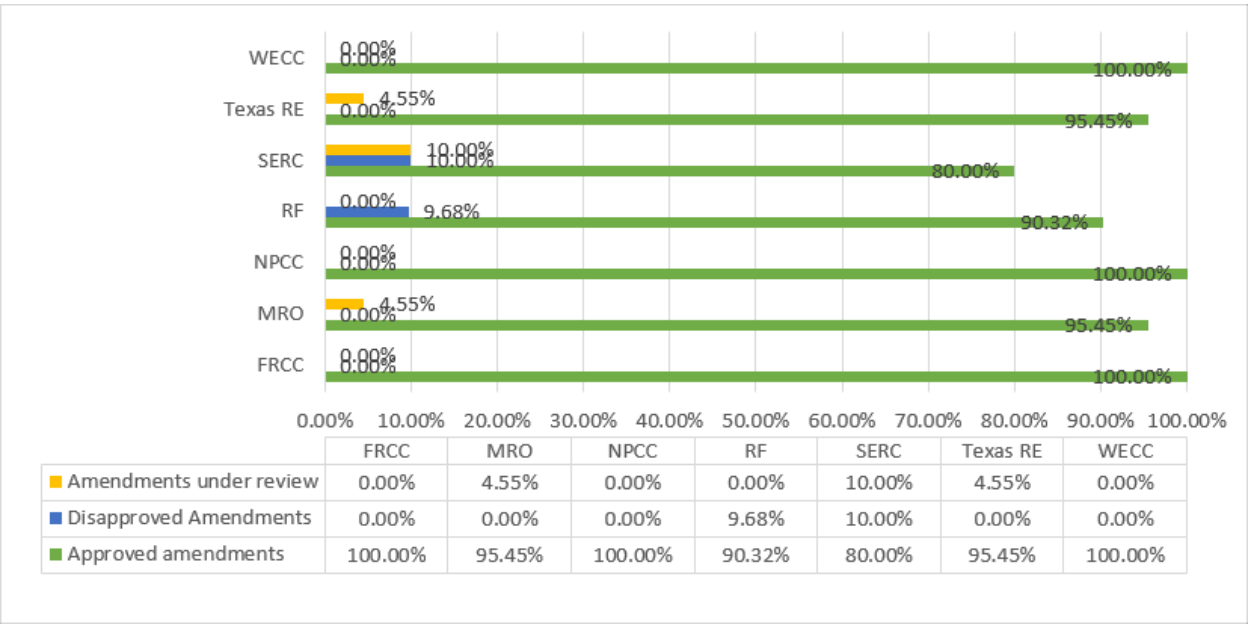
Figure 8 depicts the breakout, per Regional Entity, of the 426 ERO Enterprise approved TFEs. Registered entities in WECC continue to maintain the majority of the approved TFEs, while FRCC contained the least.

Figure 8: Total number of Approved TFEs



Registered entities submitted 161 TFE amendments during the reporting period. **Figure 9** provides a breakdown of that activity by Regional Entity. As shown below, the Regional Entities approved a majority of the amendments submitted. Of the 161 submitted amendments, the Regional Entities did not approve 12, or 7.4%. RF disapproved three TFEs due to the entity not submitting enough details and explanation for control and monitoring measures. SERC disapproved three TFEs due to the registered entity's extensive compliance record, and SERC is working with the registered entity toward a solution. Additionally, there were six TFEs still under review as of June 30, 2019.

Figure 9: Submitted TFE Amendment Activity



	FRCC	MRO	NPCC	RF	SERC	Texas RE	WECC
Amendments under review	0.00%	4.55%	0.00%	0.00%	10.00%	4.55%	0.00%
Disapproved Amendments	0.00%	0.00%	0.00%	9.68%	10.00%	0.00%	0.00%
Approved amendments	100.00%	95.45%	100.00%	90.32%	80.00%	95.45%	100.00%

Figure 10 depicts the minimum, mean, and maximum quantity of TFEs for each registered entity that has an approved TFE as of June 30, 2019. As shown below, the ERO Enterprise mean average is 3.4 TFEs per registered entity that has an approved TFE. The fewest number of TFEs a single registered entity has is one TFE. The largest number of TFEs a single registered entity has is 32 TFEs; this registered entity is located in the WECC region. WECC has the highest average at 4.56 average TFEs per registered entity that has an approved TFE. RF has the lowest mean average of 2.68 TFEs per registered entity that has an approved TFE.

Figure 10: Average TFE Quantity per Registered Entity with an Approved TFE

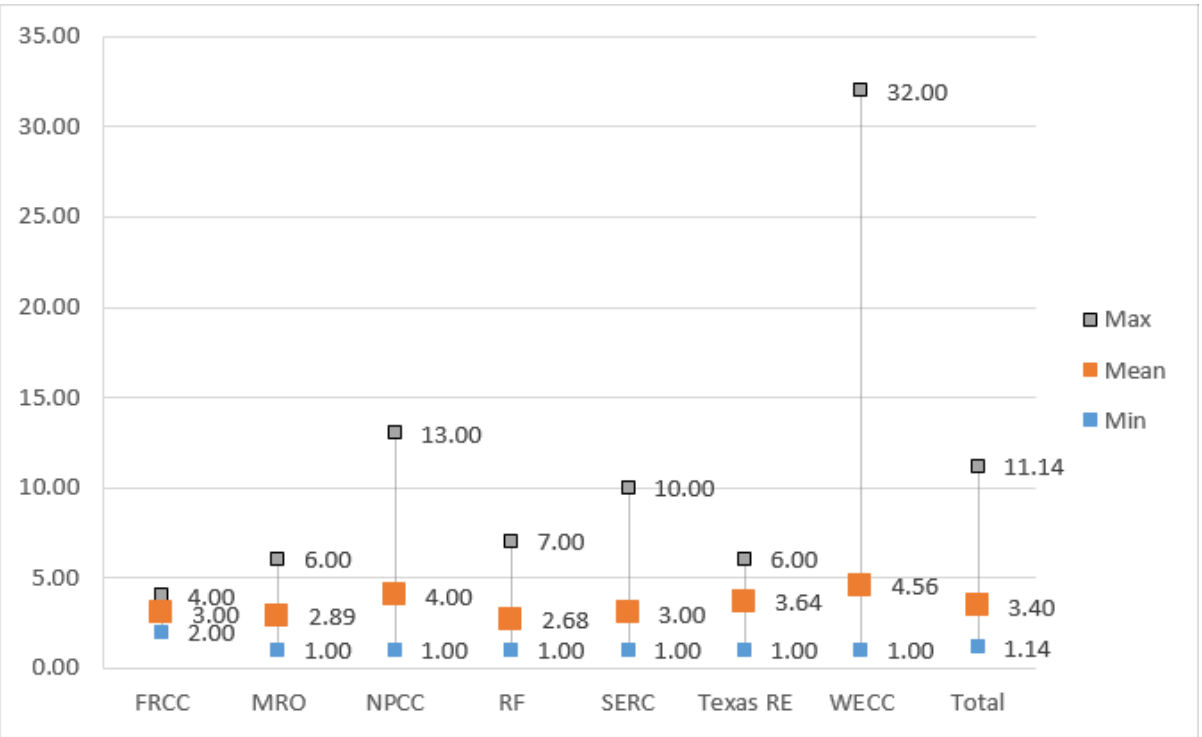
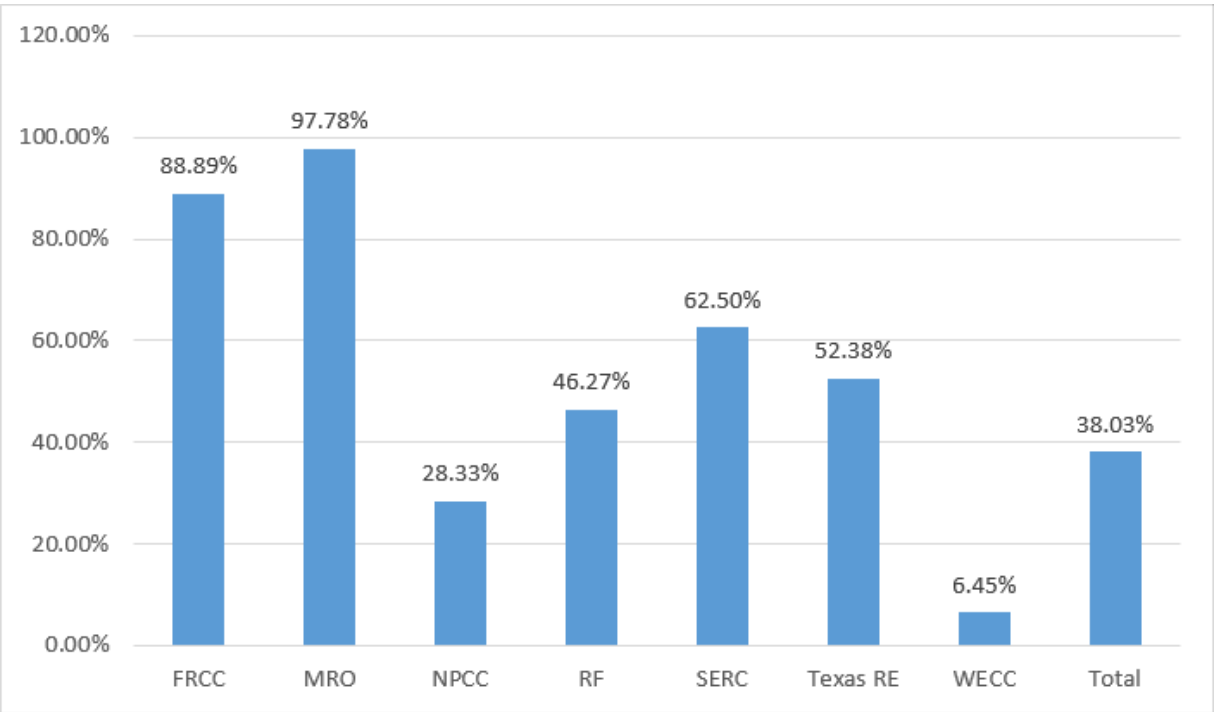


Figure 11 depicts the average percentage of TFE transactions per approved TFE during the report period. On an average, across the ERO Enterprise, when a registered entity had a TFE, 38.03% of them had a TFE transaction in 2019. In the WECC region, an average of 6.45% of registered entities with an approved TFE had some type of TFE transaction in 2019, due to the relatively high number of approved TFEs compared to a relatively small number of transactions. In comparison, MRO, with its relatively low number of approved TFEs compared to its almost equal number of TFE transactions, has an average of 97.78% approved TFEs that had some type of TFE transaction in 2019.

Figure 11: Average TFE Percentage per Registered Entities with TFE Activity



2. Categorization of the submitted and approved TFE Requests

Categorization of the submitted and approved TFE Requests to date by broad categories such as the general nature of the TFE Request, the Applicable Requirements covered by submitted and approved TFE Requests, and the types of Covered Assets that are the subject of submitted and approved TFE Requests.

To better align with the CIP standards, the TFE Task Force changed the categorization of the assets within TFEs from "Network Data Communications," "Relays," "Workstation/server," and "Other" to "Electronic Access Control and Monitoring (EACM)," "Physical Access Control System (PACS)," "Protected Cyber Asset (PCA)," "BES Cyber Asset (BCA)," "BES Cyber System (BCS)," and "Other." The "Other" category remained for those assets that do not fall into the other categories. For instance, telecommunication modems, protective relays, remote terminal units (RTUs), satellite clocks, etc. A total of 153 TFEs have assets within the "Other" category, and just over 28.5% of the "Other" assets are located within the WECC region. These assets make up over 99.5% of the TFEs that have assets within the "Other" category. Due to the categorization

changes from the 2018 report to the 2019 report, the ERO Enterprise cannot perform a comparison between specific categories. Notwithstanding, NERC reported in 2018 that TFEs cover 16,704 unique assets across the ERO Enterprise. In 2019, the total unique assets covered by TFEs totals 19,801.

Additionally, in the 2018 report, NERC discussed two TFEs from WECC that accounted for 7,608 assets,[20] which comprised almost half the assets covered by TFEs in the WECC region. WECC reviewed these TFEs outside the 2018 compliance monitoring engagement and determined that these TFEs are still valid, even with the high number of assets. These two TFEs originate at a large entity and cover devices within numerous substations. Furthermore, in 2018 NERC reported a single TFE within the Texas RE region that made up over half of the covered assets within its region. Texas RE just completed a compliance monitoring engagement that had the applicable Standard and Requirement within the audit scope, but it was outside the timeframe for this report. NERC will report on this TFE specifically in the 2020 TFE report.

Figure 12 shows total number of assets within each asset category by Regional Entity. The only consistency across Regional Entities is BES Cyber Assets as the largest asset category, except for WECC. For instance, FRCC's major asset category is BES Cyber Assets which covers 58 percent of its TFE assets, while MRO has nearly 72 percent of its assets categorized as BES Cyber Asset. Within WECC, the largest category is "Other" at almost 54 percent, with BES Cyber Assets at almost 40 percent. MRO has stated that there are three older TFEs within its TFE tracking software where the registered entity did not initially categorize the total assets; these TFEs were submitted during the CIP version 5 transition and before the software was updated to force registered entities to input categorizations of assets rather than just total asset counts, and the

[20] *See* 2018 Report at 15-16. WECC's two TFEs covering 7,608 assets will be assessed at the next compliance monitoring engagement.

registered entity has not modified the TFE since MRO began tracking asset type. MRO reported that the registered entity addresses the uncategorized asset types by providing a count of how many assets within each asset category the TFE covers while updating its TFEs, but some have not required updating. MRO also tries to encourage entities to validate their TFEs during compliance monitoring engagements.

Figure 12: Total Number of Assets with Asset Categories for Each Regional Entity

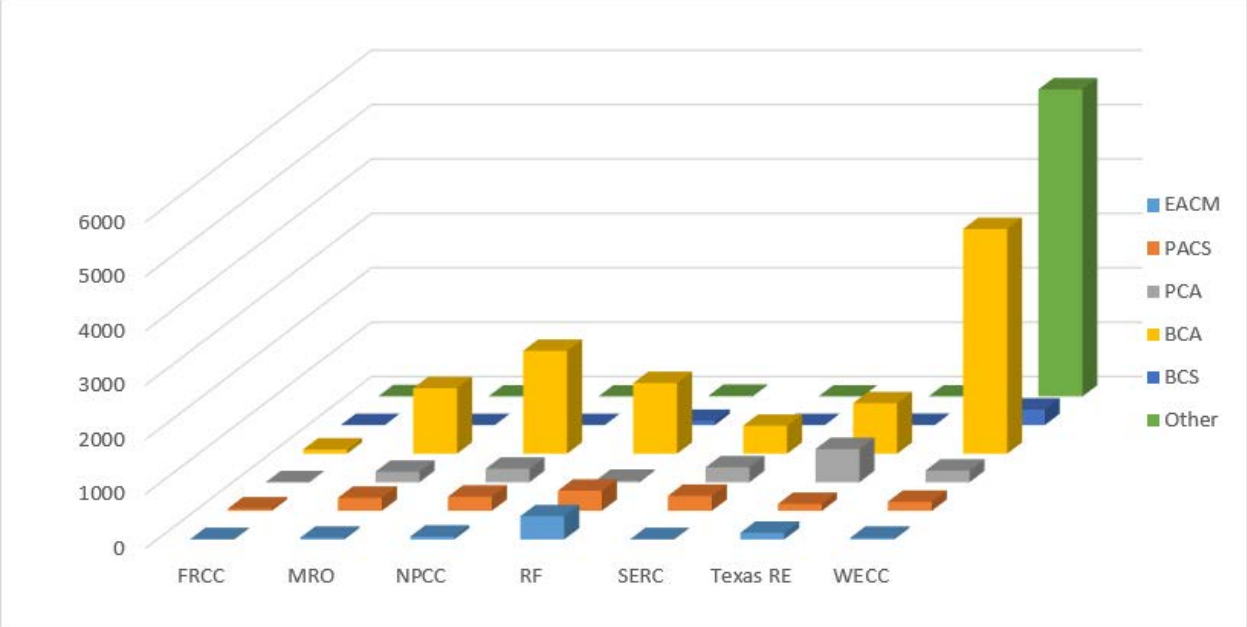
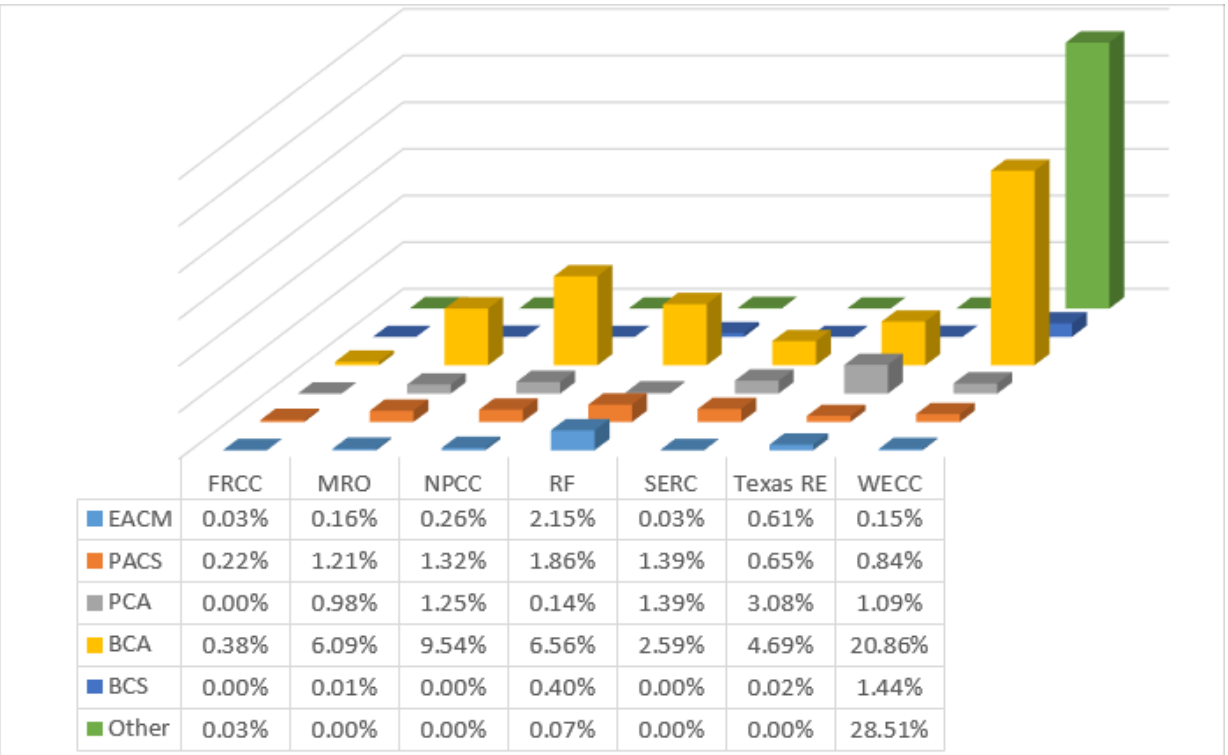


Figure 13 shows the percentage of assets within each asset category, and separated by region, compared to the total number of assets covered by TFEs in the entire ERO Enterprise. Due to the change of asset categorization, this report shows that the majority of assets that have an approved TFE are "Other." The "Other" categorization makes up almost 29 percent of the total TFE assets within the ERO Enterprise. The second highest number of assets is in the BES Cyber Asset category, making up almost 21 percent of the assets covered by TFEs. The majority of assets covered by TFEs are located within the WECC region due to the two TFEs that account for almost half of the total amount of covered assets.

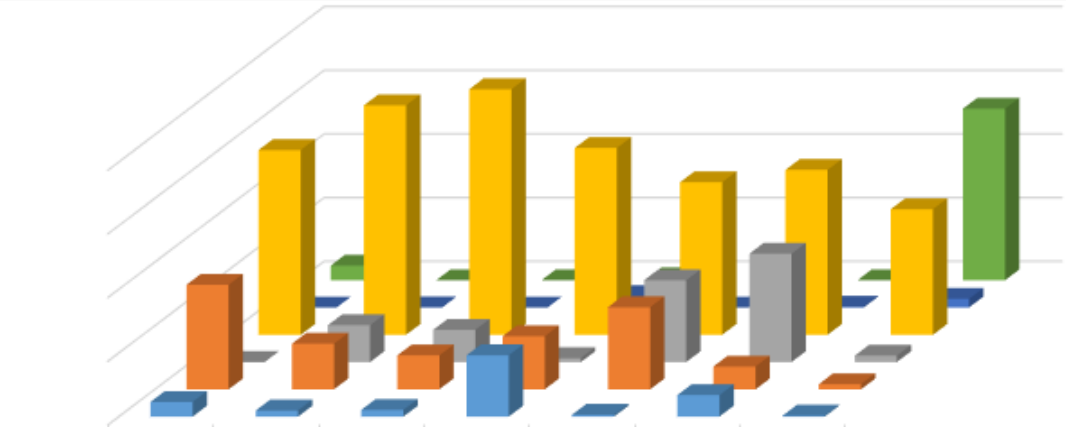
Figure 13: Percentage of Assets in each Asset Categories Compared to Total Number of Assets Covered by TFEs in the ERO Enterprise



	FRCC	MRO	NPCC	RF	SERC	Texas RE	WECC
EACM	0.03%	0.16%	0.26%	2.15%	0.03%	0.61%	0.15%
PACS	0.22%	1.21%	1.32%	1.86%	1.39%	0.65%	0.84%
PCA	0.00%	0.98%	1.25%	0.14%	1.39%	3.08%	1.09%
BCA	0.38%	6.09%	9.54%	6.56%	2.59%	4.69%	20.86%
BCS	0.00%	0.01%	0.00%	0.40%	0.00%	0.02%	1.44%
Other	0.03%	0.00%	0.00%	0.07%	0.00%	0.00%	28.51%

Figure 14 shows the total asset allocation broken out by Regional Entity. **Figure 14** is different from **Figure 12**, as **Figure 12** shows the raw number of assets for each category and within each region. **Figure 14** shows the proportion of assets in each region attributed to each category. This also shows that within each region, the BCA category has the majority of the assets, except for WECC, where the Other category contains the most assets.

Figure 14: Percentage of Assets Covered by TFEs per Regional Entity



	FRCC	MRO	NPCC	RF	SERC	Texas RE	WECC
EACM	4.58%	1.91%	2.08%	19.26%	0.56%	6.76%	0.29%
PACS	32.82%	14.35%	10.65%	16.68%	25.79%	7.15%	1.59%
PCA	0.00%	11.60%	10.12%	1.22%	25.70%	34.06%	2.05%
BCA	58.02%	72.07%	77.14%	58.68%	47.94%	51.81%	39.44%
BCS	0.00%	0.06%	0.00%	3.57%	0.00%	0.22%	2.73%
Other	4.58%	0.00%	0.00%	0.59%	0.00%	0.00%	53.90%

3. Categorization of the circumstances or justification

Categorization of the circumstances or justifications on which the approved TFEs to date were submitted and approved, by broad categories such as the need to avoid replacing existing equipment with significant remaining useful lives, unavailability of suitable equipment to achieve Strict Compliance in a timely manner, or conflicts with other statutes and regulations applicable to the Registered Entity.

The following are criteria that a registered entity may use to request a TFE:

- Not technically possible
- Operationally infeasible
- Precluded by technical limitations
- Adverse effect on bulk electric system reliability
- Cannot achieve by compliance date
- Excessive cost that exceeds reliability benefit
- Conflicts with other statutory or regulatory requirement

- Unacceptable safety risks

As in past years, registered entities tend to request a TFE based on one of the first three criteria listed above. To date, there have been no reports of Regional Entities approving TFEs based on the last two criteria.

4. Categorization of the compensating measures and mitigating measures implemented and maintained

Categorization of the compensating measures and mitigating measures implemented and maintained by registered entities pursuant to approved TFEs, by broad categories of compensating measures and mitigating measures and by types of Covered Assets.

The ERO Enterprise continues to evaluate the extent and effectiveness of compensating measures documented in TFE requests. The registered entities accomplish the majority of compensating and/or mitigating measures by compliance with requirements in related CIP Standards. As most TFEs relate to the same types of assets, the registered entities are applying the same mitigation measures for each of the TFEs to address the known risks. For instance, one registered entity filed a TFE for the inability to technically or procedurally enforce password changes (CIP-007-6 R5 Part 5.6), and the mitigating measure is the utilization of firewall rules and keeping assets logically isolated inside defined Electronic Security Perimeters. To compensate for TFEs on some BES Cyber Assets, registered entities disable interactive remote user access or physically locate assets within Physical Security Perimeters and perform background checks and training for individuals with authorized physical access (CIP-005-5 R2 Part 2.3). For BES Cyber Assets that have ports unable to be closed (CIP-007-6 R1 Part 1.1), restrictions on the Electronic Security Perimeter to utilize that particular port is often the mitigating and compensating measure.

5. TFE rejection or disapproval

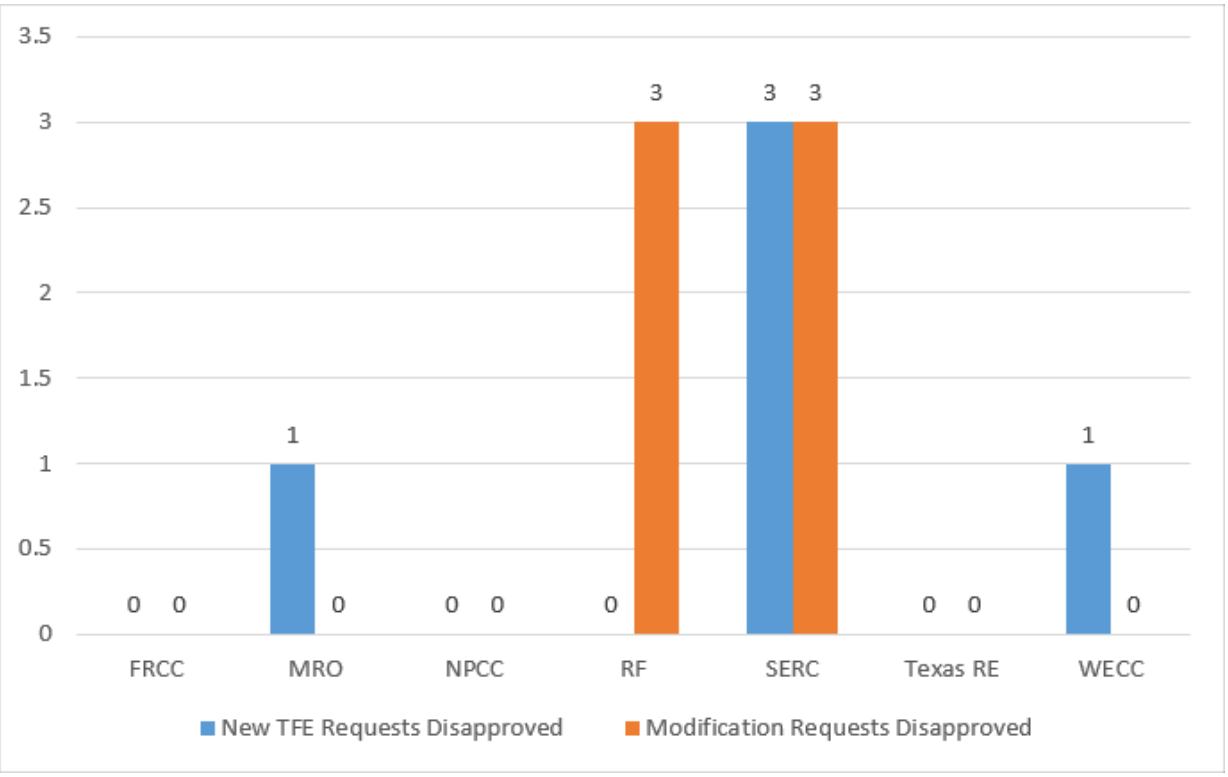
For each TFE Request that was rejected or disapproved, and for each TFE that was terminated, but for which, due to exceptional circumstances as determined by the Regional Entity, the TFE Termination Date was later than

the latest date specified in Section 5.2.6, or 9.3, as applicable, a statement of the number of days the Registered Entity was not subject to imposition of findings of violations of the Applicable Requirement or imposition of Penalties or sanctions pursuant to Section 5.3.

During the reporting period, the Regional Entities disapproved five new TFEs. Additionally, Regional Entities did not approve six TFE modifications. During the 2019 reporting period, there were no TFE termination requests that caused the effective date to be extended beyond the latest date specified in Section 5.2.6 or Section 9.3 of Appendix 4D, as applicable. For the single new TFE submitted to MRO, MRO's compliance department had a conversation with the entity's compliance contact. In this instance, the requirement for which the entity requested a TFE was neither required nor allowed, so MRO disapproved the TFE. For the RF disapprovals, the TFEs required more explanation for control and monitoring measures. For two of the new TFEs submitted to SERC, the registered entity retracted the request prior to SERC approving or disapproving. For the other disapprovals within SERC region, including the modification disapprovals, the registered entity is potentially in noncompliance with the related requirement and is working towards a solution with SERC's guidance. For WECC's single TFE disapproval, after discussing with the registered entity, it was determined that the registered entity did not need the TFE based upon the language of the associated Reliability Standard.

Figure 15 depicts the overview of these disapproved TFEs broken down by region.

Figure 15: Disapproved TFEs



6. Compliance Audit results and findings concerning the implementation and maintenance of compensating measures and mitigating measures

A discussion, on an aggregated basis, of Compliance Audit results and findings concerning the implementation and maintenance of compensating measures and mitigating measures, and the implementation of steps and the conduct of research and analyses to achieve Strict Compliance with the Applicable Requirements, by registered entities in accordance with approved TFEs.

Appendix 4D of NERC's ROP is part of the Compliance Monitoring and Enforcement Program ("CMEP") that forms the framework for Regional Entities to review and audit TFE requests. During a compliance monitoring engagement, the Regional Entity would not evaluate the registered entity on a particular requirement from the applicable Reliability Standard for which a TFE was accepted and approved, but instead evaluated against the alternative compliance obligations assumed by the registered entity (*i.e.*, compensating and mitigating measures).

All Regional Entities conduct compliance monitoring engagements where applicable approved TFEs are within the determined scope. Typically, during a compliance monitoring engagement of a registered entity with TFEs within scope, the TFEs will be reviewed (*i.e.*, based on relevant factors such as quantity, locations, etc.). Reviews include interviewing subject matter experts specifically about TFEs, and sampling evidence pertaining to a TFE's mitigating and compensating measures, among other things. Regional Entities continue to report that registered entities are managing and maintaining their TFEs within the procedural requirements of Appendix 4D. Regional Entities and registered entities are processing TFEs consistent with the CMEP framework.

7. Assessments of impacts on the reliability of the BES

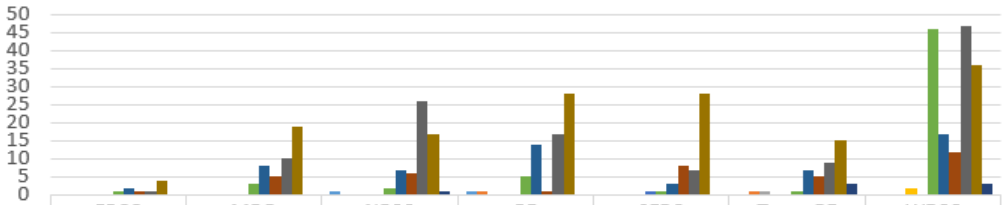
> *Assessments, by Regional Entity (and for more discrete areas within a Regional Entity, if appropriate) and in the aggregate for the United States and for the jurisdictions of other Applicable Governmental Authorities, of the Wide-Area impacts on the reliability of the Bulk Electric System of approved TFEs in the aggregate, including the compensating measures and mitigating measures that have been implemented.*

The ERO Enterprise TFE Task Force, comprised of subject matter experts from each Regional Entity and NERC, reviews TFE requests to verify sufficiency and consistency of the requests' disposition. In addition, the ERO Enterprise TFE Task Force verifies the TFEs are available for review; the ERO Enterprise performs the review when initially submitted or modified, and during compliance monitoring engagements. The ERO Enterprise TFE Task Force reports that the use of TFEs has not had an adverse impact on BES reliability. The members of the ERO Enterprise TFE Task Force reported similar experiences (among different regions) with the execution and management of the TFE process and the manner in which it impacted BES reliability. Additionally, the Task Force reports that a large majority of registered entities have implemented multiple compensating and mitigating measures for Covered Assets. In general, the

mitigating and compensating measures implemented for approved TFEs in lieu of strict compliance with applicable CIP Reliability Standards have accomplished the stated alternate compliance objectives. As a result, the level of BES security achieved through the TFE process is comparable to strict compliance with the applicable Reliability Standards.

Figure 16 shows, per region, the number of TFEs for each requirement that registered entities submitted to the Regional Entities. The majority of the approved TFEs are for CIP-007-6 R5 Part 5.7. CIP-006-6 R1 Part 1.3 and CIP-005-5 R2 Part 2.2 have the fewest number of TFEs with one TFE each.

Figure 16: TFE Breakout per Requirement and Part



	FRCC	MRO	NPCC	RF	SERC	Texas RE	WECC
CIP-005-5 R1 Part 1.4	0	0	1	1	0	0	0
CIP-005-5 R2 Part 2.1	0	0	0	1	0	1	0
CIP-005-5 R2 Part 2.2	0	0	0	0	0	1	0
CIP-005-5 R2 Part 2.3	0	0	0	0	0	0	2
CIP-006-6 R1 Part 1.3	0	0	0	0	1	0	0
CIP-007-6 R1 Part 1.1	1	3	2	5	1	1	46
CIP-007-6 R4 Part 4.3	2	8	7	14	3	7	17
CIP-007-6 R5 Part 5.1	1	5	6	1	8	5	12
CIP-007-6 R5 Part 5.6	1	10	26	17	7	9	47
CIP-007-6 R5 Part 5.7	4	19	17	28	28	15	36
CIP-010-2 R3 Part 3.2	0	0	1	0	0	3	3

8. Efforts to eliminate future reliance on TFEs

Discussion of efforts to eliminate future reliance on TFEs.

In the past, the value of a TFE was the safe harbor it provides when a registered entity could not achieve strict compliance to certain Reliability Standards. As referenced in Order No. 706, TFEs are rooted in the problem of legacy equipment and the economic considerations

involved in the replacement of such equipment before the end of its useful life.[21] As registered entities increasingly move away from legacy equipment, the value of the TFE program, as currently constructed, is diminishing in comparison to the program's administrative burden. However, despite the decrease in the number of approved TFEs and the total assets covered by TFEs, the level of effort required of the registered entity and Regional Entity to maintain and administer a TFE continues to increase. TFE record-keeping, as currently required by Appendix 4D of the NERC ROP, is burdensome for the Regional Entities and registered entities alike, creating work efforts that may outweigh any perceived benefit. In addition, ERO Enterprise CMEP processes used to assess general compliance with the CIP Reliability Standards are equally effective in evaluating the compensating and mitigation measures when strict compliance is "technically infeasible." The ERO Enterprise TFE Task Force does not believe that registered entities achieve additional reliability or security benefits by administratively submitting and modifying TFEs.

To that end, NERC and the Regional Entities are considering alternatives to the current TFE program to alleviate the administrative burden on registered entities and the ERO Enterprise. During quarterly meetings, the ERO Enterprise TFE Task Force has focused on TFE management, administrative processes, and approaches to making the processes more effective and efficient for the Regional Entities and registered entities. The members of the ERO Enterprise TFE Task Force concluded that the existing TFE processes are labor intensive and do not provide additional mitigation of significant risks apart from the application of existing CMEP tools such as Compliance Audits, Spot Checks, Self-Certifications, and Self-Reports. The ERO Enterprise TFE Task Force has stated that there may be opportunities to retain the same awareness and risk

[21] Order No. 706 at P 157.

mitigation of the TFE program while reducing the administrative burden. For example, NERC could allow a registered entity to maintain the exception without prior approval, provided that the registered entity could demonstrate during compliance monitoring engagements that: (i) the exception is reasonable; and (ii) the registered entity implemented appropriate mitigation measures in lieu of strict compliance. As NERC considers alternatives to the TFE program as presently constituted, it will consult with Commission staff. NERC will seek Commission approval for any proposed changes to the NERC ROP. Additionally, the Standards Drafting Team for Project 2016-02 Modifications to CIP Standards[22] may propose changes to the TFE language as found in currently approved CIP Reliability Standards.

9. Material Change Reports

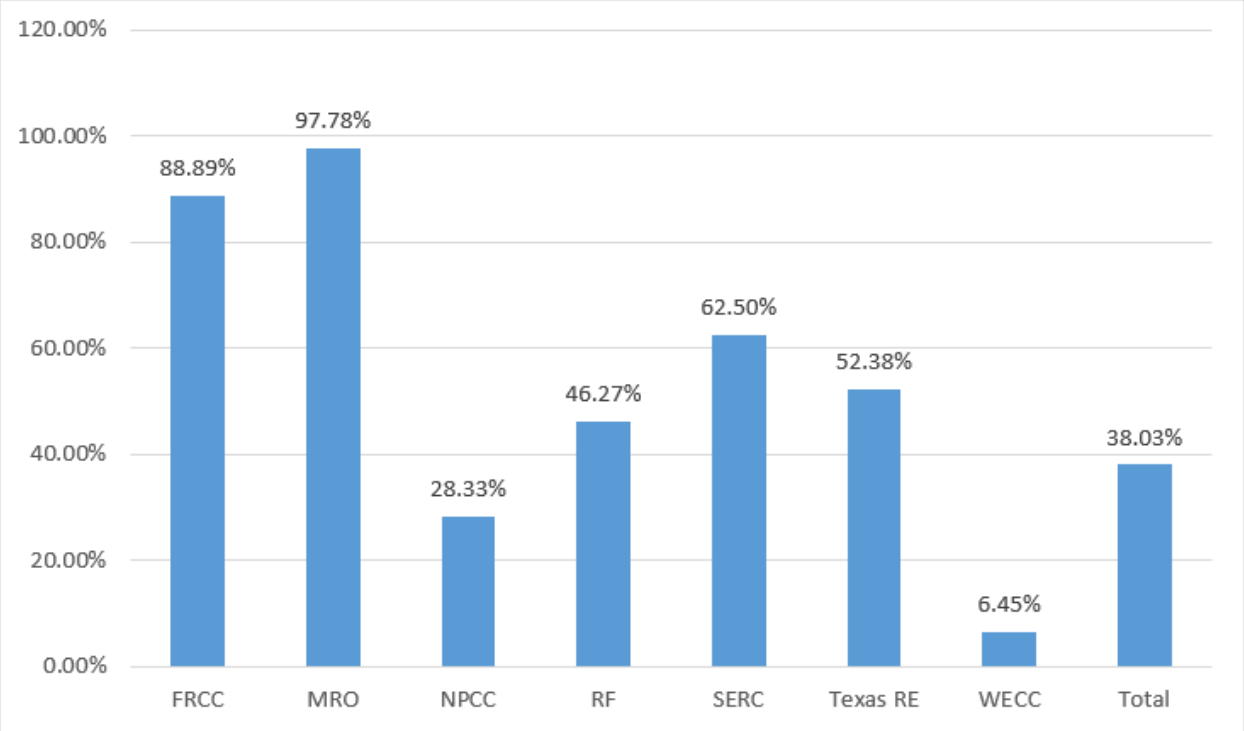
Data and information regarding Material Change Reports, including the number of Material Change Reports filed annually and information regarding the types of circumstances or events that led to Material Changes, as well as any additional information NERC believes would be useful.

When registered entities modify the information associated with approved TFEs, the registered entity submits updates to the relevant Regional Entity via a Material Change Report ("MCR"). An MCR requires approval by the Regional Entity, which can then refer to the updated, current data when undertaking compliance monitoring activities (e.g., Compliance Audits, Spot Checks, Self-Certifications, etc.). **Figure 17** below shows the percentage of amendments per approved TFEs within each region. The majority of requested changes occur for asset count changes and administrative updates, such as changing the primary contact's information. MCR requests have declined from 2018 to 2019. In 2018, some regions reported that every approved TFE had an MCR submitted for it. The 2019 average across the ERO Enterprise is just over 38%,

[22] Project 2016-02 Modifications to CIP Standards, https://www.nerc.com/pa/Stand/Pages/Project 2016-02 Modifications to CIP Standards.aspx.

which means there is a 38% chance a registered entity submitted an MCR to modify an approved TFE.

Figure 17: TFE Amendments to Approved TFEs per Regional Entity



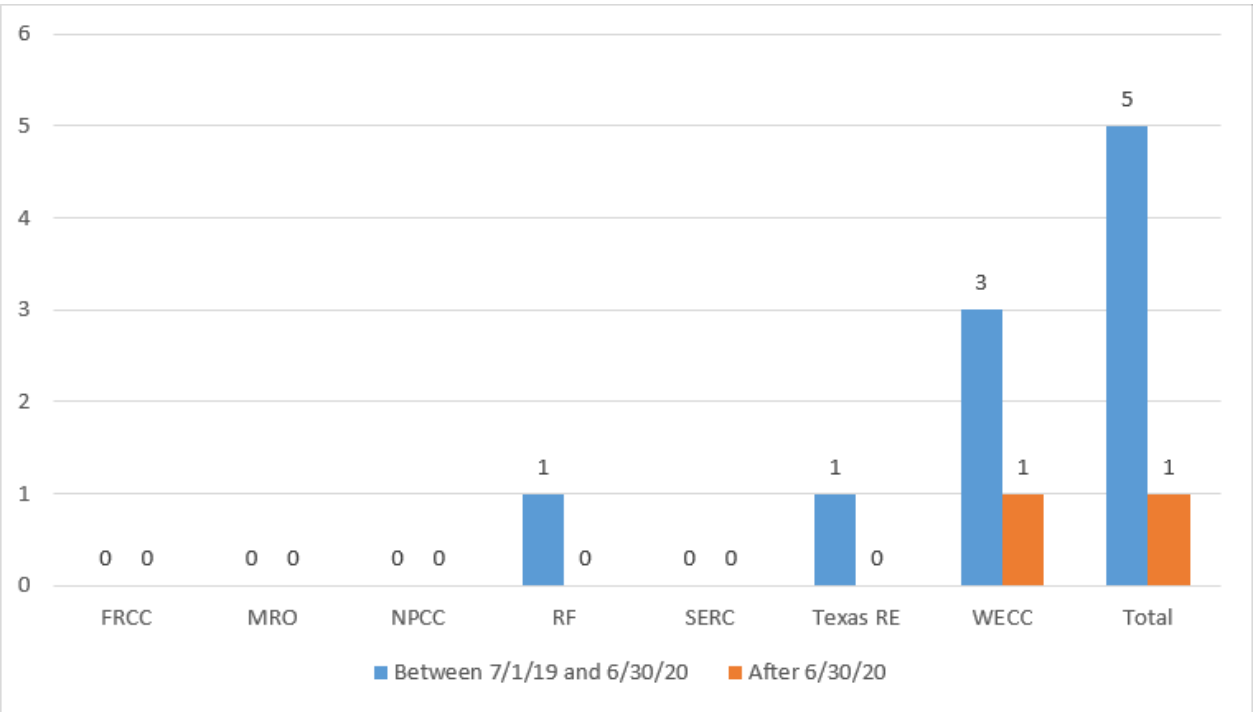
10. Additional information about TFEs and their TFE Expiration Dates

Additional information about TFEs and their TFE Expiration Dates, including the number of TFEs by expiration year and CIP Standard requirement, the percentage of currently approved TFEs without TFE Expiration Dates, and the number of new TFEs approved without expiration dates annually.

In its September 2013 Order, the Commission directed NERC to provide additional information in the annual TFE reports related to TFEs with and without expiration dates. As reported previously, most TFEs do not have expiration dates. For the next TFE reporting period, July 1, 2019 to June 30, 2020, there are five TFEs scheduled to expire. In addition, one TFE for CIP-005-5 Requirement R2, Part 2.3 is scheduled to expire in the 2021 TFE reporting period.

Figure 18 shows the breakdown of TFEs with future expiration dates.

Figure 18: TFEs to Expire in Future



11. Consistency in Review, Approval and Disapproval of TFE Requests

Appendix 4D, Section 11.1 of the NERC ROP requires that NERC and the Regional Entities collaborate to assure "consistency in the review, approval and disapproval of TFE Requests…." Also, as noted above, Section 11.2.4 of the Appendix 4D requires that NERC submit with each Annual TFE Report certain information concerning the manner in which Regional Entities have made determinations to approve or disapprove TFE requests. The scope document for the ERO Enterprise TFE Task Force describes activities and deliverables that support this effort:

- Review Regional Entities' processes and performance in administering TFE Requests and Material Change Reports;
- Evaluate whether the administration of TFE activities among the Regional Entities yields consistent results;
- Assess compensating and mitigating measures described in TFEs for quality and sufficiency;

- Review approved and disapproved TFE Requests or Material Change Reports for consistency; and
- Monitor approved TFEs throughout their life cycle to determine whether they remain necessary and effective.

NERC and the ERO Enterprise TFE Task Force will continue to collaborate on these actions in 2019 and 2020. Additionally, NERC and the ERO Enterprise TFE Task Force will be conducting more rigorous reviews of the TFE data throughout the year to verify correct information is being presented to FERC.

VI. CONCLUSION

For the foregoing reasons, NERC respectfully requests that the Commission accept the 2019 Annual Report.

Respectfully submitted,

/s/ Lauren A. Perotti

Lauren A. Perotti
Senior Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
202-400-3000
lauren.perotti@nerc.net

Counsel for North American Electric Reliability Corporation

September 26, 2019

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
North American Electric Reliability
Corporation
Docket No. RR19-6-000

Issued: August 22, 2019

Owen E. MacBride
Schiff Hardin LLP
233 South Wacker Drive, Suite 7100
Chicago, IL 60606

Reference: Report of Comparisons of Budgeted to Actual Costs for 2018

On May 30, 2019, North American Electric Reliability Corporation (NERC) submitted a report of comparisons of budgeted to actual costs for 2018 for NERC and the Regional Entities.

Notice of this filing was published in the *Federal Register*, with protests and interventions due on or before June 20, 2019. 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 adverse comments were received.

NERC's uncontested filing is accepted pursuant to the relevant authority delegated to the Director, Office of Energy Market Regulation, under 18 C.F.R. § 375.307.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.307(a)(2)(vi). This action does not constitute approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service provided for in the filed documents. Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may 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.

Issued by: Penny S. Murrell, Director, Division of Electric Power Regulation – Central

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Breaker Failure due to Multiple Reclose Attempts

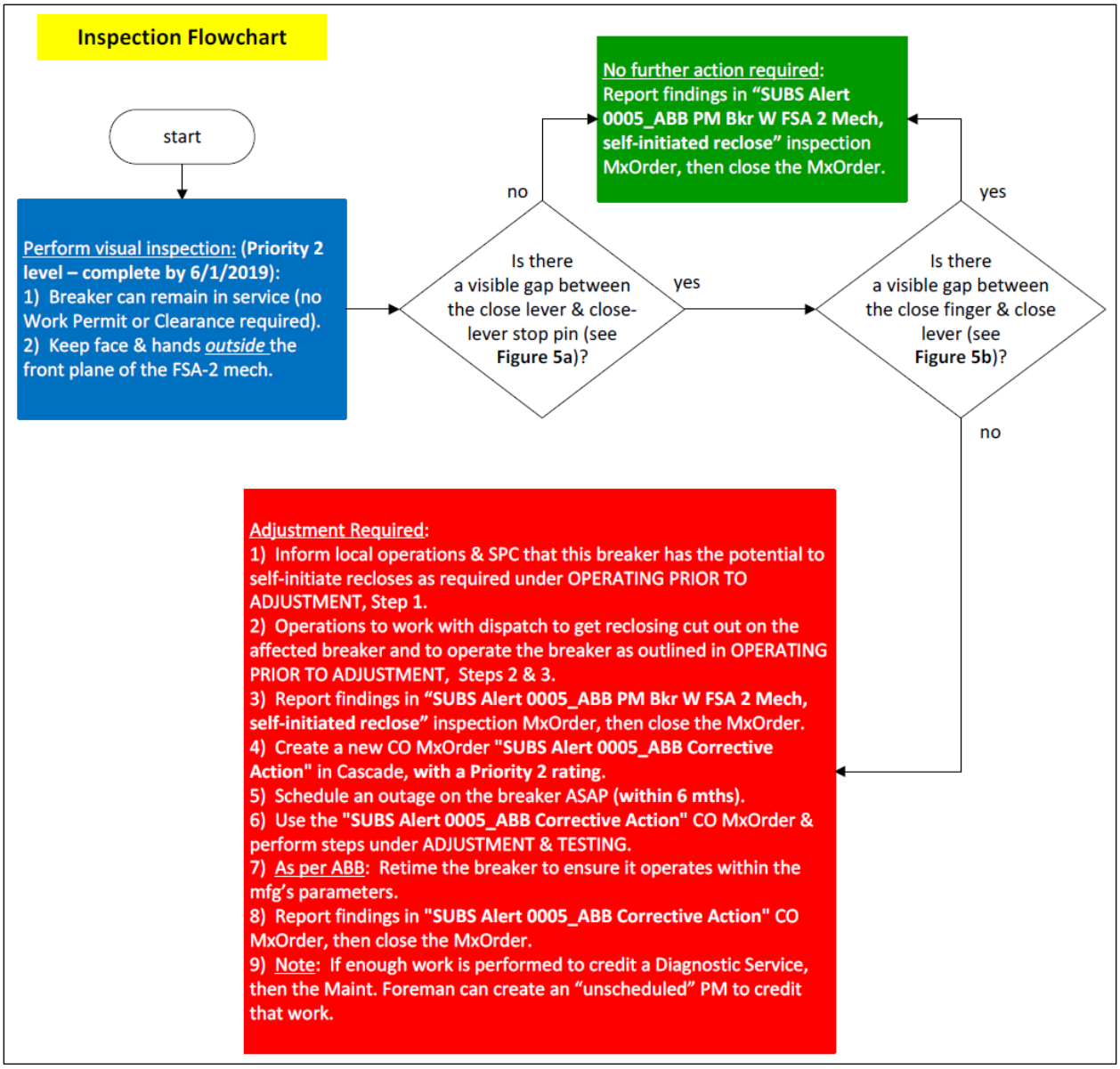
Primary Interest Groups
Transmission Operators (TOPs)
Transmission Owners (TOs)
Generation Owners (GOs)
Generation Operators (GOPs)

Problem Statement
During a 115 kV permanent line fault, a line breaker malfunctioned and reclosed into the fault eight times before failing internally, resulting in a bus differential lockout clearing all breakers on the 115 kV bus. After working with the manufacturer, it was determined that the issue was caused by maintenance being done on the breaker incorrectly.

Details
During a winter storm, a tree fell into a 115 kV line, breaking the C-phase conductor. The C-phase conductor fell and made permanent contact with the grounded transmission tower. The breakers at both ends of the line properly tripped to clear the fault. Both breakers then properly attempted a reclose and then tripped back open due to the permanent fault. After this second trip, one of the breakers malfunctioned and improperly self-initiated reclosures into the faulted line seven more times. During the final reclose attempt into the faulted line, the breaker failed to interrupt the fault and eventually faulted internally on the C-phase, causing the main bus differential lockout relay to properly operate and open all breakers on the 115 kV bus. All relaying operations worked properly for this event. The failed breaker was removed from service for further investigation and a replacement breaker was installed in its place.

Corrective Actions
The failed breaker was an ABB 121PM40-20 breaker and is a common breaker on this entity's system. The potential impact of future events with this type of breaker made this a high priority for the entity. The entity enlisted the manufacturer's help in troubleshooting the breaker. It was found that there was an insufficient gap between the top of the close-coil plunger and the close lever in the breaker's FSA-2 closing mechanism. The instructions for this breaker call for a 2–4 mm gap, but this breaker had a 0 mm gap. The troubleshooting team determined the issue could be visually identified without removing the breakers from service. They developed a procedure for field personnel to identify and correct this issue on other breakers on their system. Excerpts of the essential parts of that procedure can be found on the following pages.

Excerpts from the procedure manual developed to identify and correct issues:



Inspection Method:

1. Breaker can remain in service, no Work Permit or Clearance required.
2. Keep face & hands *outside the front plane* of the FSA-2 mechanism.
3. Inspect for visible gaps between:
    a. Close lever and the close-lever stop pin as shown in **Figure 5a**.
    b. Close finger and close lever as shown in **Figure 5b**.

Inspection Results:

1. **Figure 5a:**

    a. No Visible Gap exists:
        i. Close lever is correctly resting on the close-lever stop pin. No further action required.
        ii. Report findings in **"SUBS Alert 0005_ABB PM Bkr W FSA-2 Mech, self-initiated reclose"** inspection MxOrder, then close the MxOrder. **These are Priority 2 MxOrders and should be completed by 6/1/2019.**

    b. Visible Gap exists: Possible issue, more inspection required. Go to Inspection Results / Step 2.

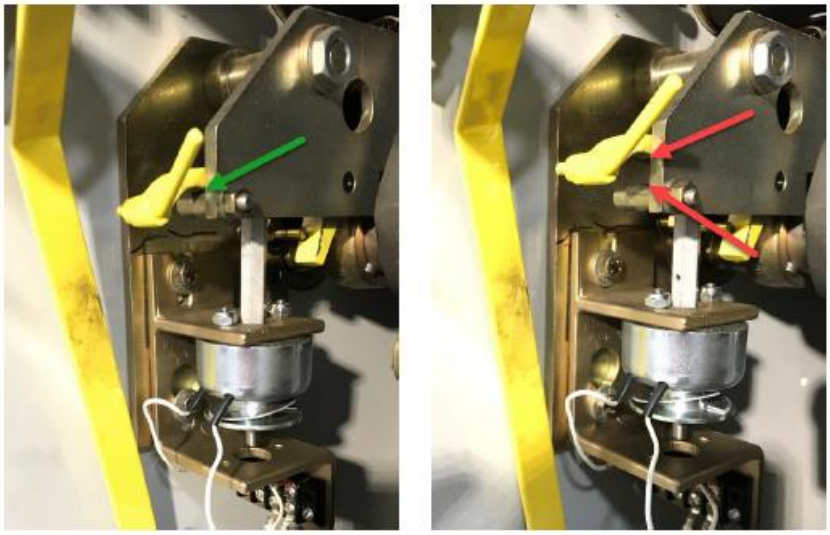


Figure 5a – Visible Gap Between Close Lever and The Close-Lever Stop Pin

2. **Figure 5b:**

   a. Visible Gap exists:
      i. No further action required.
      ii. Report findings in **"SUBS Alert 0005_ABB PM Bkr W FSA-2 Mech, self-initiated reclose"** inspection MxOrder, then close the MxOrder. **These are Priority 2 MxOrders and should be completed by 6/1/2019.**

   b. No Visible Gap exists:
      i. Inform local operations & SPC that this breaker has the potential to self-initiate recloses as required under **OPERATING PRIOR TO ADJUSTMENT**, Step 1.
      ii. Operations to work with dispatch to get reclosing cut out on the affected breaker and to operate the breaker as outlined in **OPERATING PRIOR TO ADJUSTMENT**, Steps 2 & 3.
      iii. Report findings in **"SUBS Alert 0005_ABB PM Bkr W FSA-2 Mech, self-initiated reclose"**, Priority 2 inspection MxOrder, then close the MxOrder.
      iv. Create a new CO MxOrder **"SUBS Alert 0005_ABB Corrective Action"** in Cascade, **with a Priority 2 rating.**
      v. Schedule an outage on the breaker as soon as possible (within 6 months).
      vi. Use the **"SUBS Alert 0005_ABB Corrective Action"** CO MxOrder, and perform the steps listed under **ADJUSTMENT** & **TESTING** below.
      vii. As per ABB: Retime the breaker to ensure that it operates within manufacturer's parameters.
      viii. Report findings in the **"SUBS Alert 0005_ABB Corrective Action"** CO MxOrder, then close the MxOrder.
      ix. Note: If enough work is performed to credit a Diagnostic Service, then the Maintenance Foreman can create an "unscheduled" PM to credit that work.

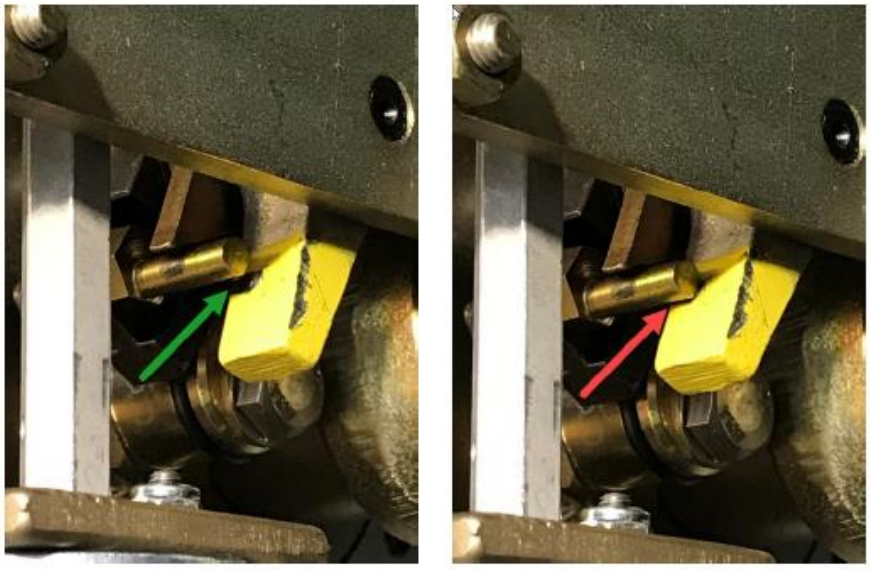


Figure 5b – Visible Gap Between Close Finger and Close Lever

OPERATING PRIOR TO ADJUSTMENT:

1. Inform local operations and SPC that this breaker has the ability to self-initiate recloses during permanent-fault conditions.
2. Local Operations to work with dispatch to get reclosing on the affected breaker cutout. A Caution tag will be placed locally at the substation by the operator, as well as in SCADA by the dispatcher.
3. With reclosing cutout, the breaker will never attempt a reclose and will not self-initiate reclosing. However, the following steps need to be taken into account if a fault occurs on the associated line:
    a. **SUSPECT BREAKER ON ONLY ONE END OF THE LINE** – If reclosing is cutout on one end of the line, that end will not reclose without manual intervention. In these steps the breaker with reclosing cutout is referred to as the "suspect breaker", and the breaker with reclosing cut-in is referred to as the "non-suspect" breaker. There are two plausible scenarios:
        i. If the non-suspect breaker has successfully reclosed, dispatch can feel confident in closing the suspect breaker since the fault was transient, as demonstrated by the successful reclosing.
        ii. If the non-suspect breaker did not successfully reclose, that is an indication that a permanent fault may be present. In this case dispatch should attempt to close only the non-suspect breaker. If the non-suspect breaker remains closed, dispatch can feel confident that the faulted condition no longer exists, and the suspect breaker can also be remotely closed. If the non-suspect breaker trips again after dispatch attempts to close it, TLM should patrol the line to determine if there is still a faulted section of the line. Dispatch should not attempt to close the suspect breaker before the non-suspect breaker closes successfully, which would demonstrate that the faulted condition is no longer present.
    b. **SUSPECT BREAKERS ON BOTH ENDS OF THE LINE** – If reclosing is cutout on both ends of the line, the line will remain de-energized and neither breaker will attempt a reclose. In this case TLM should patrol the line to determine if there is still a faulted section of the line. Dispatch ***shall not*** attempt to close breakers on either end until there is assurance the fault is no longer present. If either breaker is closed and the permanent fault condition still exists, the breaker could begin self-initiating recloses into the faulted line with no way to stop the self-initiated reclose / relay trip cycles.

ADJUSTMENT:

1. Remove breaker from service.
2. Remove all stored energy from the close & trip springs as follows:
    a. Operate the breaker into the closed position, wait for the charging motor to completely charge the close springs and shut off.
    b. Turn OFF power to the AC & DC motor bus.
    c. Press & release the trip button, followed by an immediate press & release of the close button, followed by an immediate press & release of the trip button.
3. Loosen bolts holding the close-coil mounting bracket to the close-latch assembly. Drop & adjust the close-coil mounting bracket. Attain the mfg's recommended gap between the top of the close-coil plunger and the close lever (with the lever lifted to touch the release finger) as outlined in the instruction book.
4. Tighten bolts holding the close-coil mounting bracket to the close-latch assembly.
5. Turn ON power to the AC & DC motor bus.
6. Perform steps listed under **TESTING** to ensure that issue is resolved.

TESTING:

1. **Perform an O-C-O test simulating a relay-initiated response to a permanent fault:**
   a. Operate the breaker into the closed position, wait for the charging motor to completely charge the close springs and shut off.
   b. Press & release the trip button. Press & release of the close button, followed by an immediate press & release of the trip button. Wait for the charging motor to completely charge the close springs and shut off.
   c. Repeat steps 1a & 1b two more times (for a total of three O-C-O tests).
2. Results:
   a. Breaker trips/closes/trips, charging motor runs & charges the close springs, breaker stays open for *all* of the three O-C-O tests without any self-initiated recloses. No further adjustment required. Retime the breaker to ensure that it operates within manufacturer's parameters. Work with local operations to have reclosing cut-in when the breaker is returned to service.
   b. Breaker trips/closes/trips, charging motor runs & charges the close springs, close cam does not stay on latch, breaker self-initiates a reclose on *any* of the 3 tests.
      i. Perform steps listed under **ADJUSTMENT**, using a different gapping that is still within the manufacturer's limits. Then, repeat **TESTING** to ensure that issue is resolved.
      ii. Install a new close-latch assembly. Perform steps listed under **ADJUSTMENT**. Then, repeat **TESTING** to ensure that issue is resolved.

Lesson Learned

The failed breaker was an ABB 121PM40-20 breaker and the entity engaged in a contract to have an ABB representative assist in troubleshooting the breaker. It was found that there was an insufficient gap between the top of the close-coil plunger and the close lever in the breaker's FSA-2 mechanism. The instructions for this breaker call for a 2–4 mm gap but this breaker had a 0 mm gap. There were felt-pen markings near the close-coil brackets that indicated the close-latch assembly, close coil, or both had been worked on in the past. It is likely that this gap insufficiency was introduced during the time of work rather than during the manufacturing process. The troubleshooting team was able to replicate the breaker self-initiated reclose issue and once the gap adjustment was made the self-initiated reclosing no longer occurred.

It is important to note that the self-reclosing only occurs when there is a "trip-reclose-trip" sequence of operations like there would be during a permanent fault on a position that utilizes automatic reclosing. Therefore, this problem does not pose a safety hazard for hold orders or cutting out reclosing on breakers with this FSA-2 mechanism type. The entity has a large number of these breakers and issued a substation maintenance alert to all districts with ABB 72PM, 121PM, and 145PM breakers equipped with FSA-2 mechanisms.

In addition to the alert that was issued, the entity included a step to verify the gap parameters in their breaker diagnostic checklists that are used during maintenance activities.

The entity wants to clarify that breakers with this type of mechanism *do not* come from the factory with this issue. The issue can only be introduced when the close-latch assembly is replaced, when a close-coil is replaced, or when both components are replaced. If maintenance crews check and adjust the gap between the top of the close-coil plunger and the close-lever using the parameters listed in the

instruction book after parts replacement, then the self-reclosing issue *cannot* occur.

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 is asking entities who have taken action on this lesson learned to respond to 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)	WECC Event Analysis
Source of Lesson Learned:	WECC
Lesson Learned #:	20190804
Date Published:	August 13, 2019
Category:	Transmission 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.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Risks Posed by Firewall Firmware Vulnerabilities

Primary Interest Groups

Transmission Operators (TOPs)
Transmission Owners (TOs)
Generation Operators (GOPs)
Generation Owners (GOs)
Distribution Providers (DPs)
Reliability Coordinators (RCs)
Balancing Authorities (BAs)

Problem Statement

A vulnerability in the web interface of a vendor's firewall was exploited, allowing an unauthenticated attacker to cause unexpected reboots of the devices. This resulted in a denial of service (DoS)[1] condition at a low-impact control center and multiple remote low-impact generation sites. These unexpected reboots resulted in brief communications outages (i.e., less than five minutes) between field devices at sites and between the sites and the control center.

Details

A registered entity with a low-impact control center experienced brief (i.e., less than five minutes) outages of internet-facing firewalls that controlled communications between the control center and multiple remote generation sites and between equipment on these sites. The affected firewalls were all perimeter devices that served as the outer security layer. These outages had no impact to generation. Seeing several of these outages at different sites raised suspicion and led to a more in-depth investigation. This investigation revealed that the communications outages were due to reboots of the firewalls at each of the sites. The entity's system monitoring tools also provided notification of the firewall reboots. These records show the firewall reboots occurred over a 10-hour time period with each firewall showing offline status for less than five minutes.

After an initial internal investigation, the entity decided that, in order to fully characterize the nature of the reboots and the potential causes, the firewall manufacturer should review logs. Subsequent analysis determined that the reboots were initiated by an external entity exploiting a known firewall vulnerability. After receiving this notification, the entity initiated their event reporting procedure as dictated by their cybersecurity incident response plan. Along with identifying the cause of the reboots, the firewall manufacturer offered a firmware update that would address the vulnerability. The entity assessed the update details and determined it was appropriate to deploy immediately. The entity first deployed the

[1] See previous NERC Lessons Learned LL20181001, "Networking Packet Broadcast Storms" for a discussion of a self-inflicted problem having similar symptoms to a DoS attack.

firmware patch on a firewall within a non-critical environment[2] at the entity's control center that would not impact operational assets and monitored the changes for any adverse effects. After seeing no adverse effects, the entity deployed the firmware patch at an operational generation site that night. After monitoring traffic in the production environment overnight and early the following morning, the entity deployed the update to all remaining BES assets that had common hardware with the firmware vulnerability.

Corrective Actions

After completing mitigation efforts to address the immediate risk posed by the firmware vulnerability, the entity performed an internal assessment to identify internal process improvements to reduce the likelihood of an event with a similar cause from happening again. Given that a firmware update to address the exploited vulnerability had been released prior to the event, the entity's process for assessing and implementing firmware updates was reviewed. Based on this review, the entity decided to implement a more formal and more frequent review of vendor firmware updates that would be tracked within internal compliance tracking software. It should be noted that the entity was already working to develop internal procedures to support this process; however, these were not completed or being practiced at the time of the event. Additionally, the entity now utilizes firewall rules that restrict allowable traffic to the minimum required to operate the assets.

Lesson Learned

Even in cases involving low-Impact BES assets, an entity should strive for good cyber security policies and procedures. Consider some of the following lessons:

- Follow good industry practices for vulnerability and patch management.
  - Close monitoring of vendor firmware releases and their implementation is a key element of a strong cybersecurity posture. Firewall firmware updates need to be reviewed as quickly as possible after release for risk and applicability.
  - Testing in a development (or "sandbox") environment prior to deployment is the best way to check for the patch's potential to introduce new problems.
- Reduce and control your attack surface.
  - Have as few internet facing devices as possible.
- Use virtual private networks.
- Use access control lists (ACLs) to filter inbound traffic prior to handling by the firewall; minimize the traffic through a denial by default configuration with whitelisting for the allowed and expected IP addresses. Limit outbound traffic similarly for information security purposes.

[2] Even in an emergency, still test before applying patches to control systems to ensure no adverse effects upon patch implementation, preferably testing in a development environment. If that is not possible, then test in a less critical part of the environment as was done in this case. Also, when designing the network, include the ability to perform maintenance on VPN terminators without having to take down the edge firewall because if it is hard or expensive to do, the chances it won't be completed increase.

- Layer defenses. It is harder to penetrate a screening router, a virtual private network terminator, and a firewall in series than just a firewall (assuming the ACLs and other configurations are appropriate).
- Segment your network. Restrict lateral communication to necessary and expected traffic to reduce the impact of a breach.
- Know your exploitable vulnerabilities so you can pursue fixes.
  - Maintain awareness of vulnerabilities and understanding of those in your environment through product vendor websites and user groups and third party resources, such as the National Vulnerability Database[3], SANS Internet Storm Center[4], Exploit Database[5], etc.
  - Consider asking the Department of Homeland Security under the "National Cybersecurity Assessment and Technical Services (NCATS) program[6]" (or a security vendor) to conduct external vulnerability scanning.
  - Join the Electricity Information Sharing and Analysis Center (E-ISAC)[7].
- Monitor your network.
  - System performance monitoring increases the likelihood that brief communications outages with little actual impact to generator operations will be more closely investigated. This is how this lesson learned came to be.
  - Use tools for firewall log analysis to detect events and support post-event investigations. This will provide information about the nature of attacks and exploits used.
  - Report attacks and suspicious activity to the E-ISAC.
- Employ redundant solutions to provide resilience and on-line maintenance capabilities:
  - Of the entity's sites impacted by the firewall reboot, not all experienced communications disruptions. Following the event, it was discovered that the sites running firewalls in high-availability/redundant pair configuration maintained communications during the reboots. At sites utilizing this design, the secondary firewall maintained communications while the primary firewall rebooted.
  - Firewall redundancy preserves functionality in the event of a single firewall failure.
  - Firewall redundancy reduces impact of firmware updates since each firewall can be updated independently without interrupting communications during the update process.

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 is asking

[3] National Vulnerability Database https://nvd.nist.gov/
[4] SANS Internet Storm Center https://isc.sans.edu/
[5] Exploit Database https://www.exploit.db.com/
[6] National Cybersecurity Assessment and Technical Services https://www.us-cert.gov/resources/ncats
[7] Electricity Information Sharing and Analysis Center https://www.nerc.com/pa/CI/ESISAC/Pages/default.aspx

entities who have taken action on this lesson learned to respond to the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

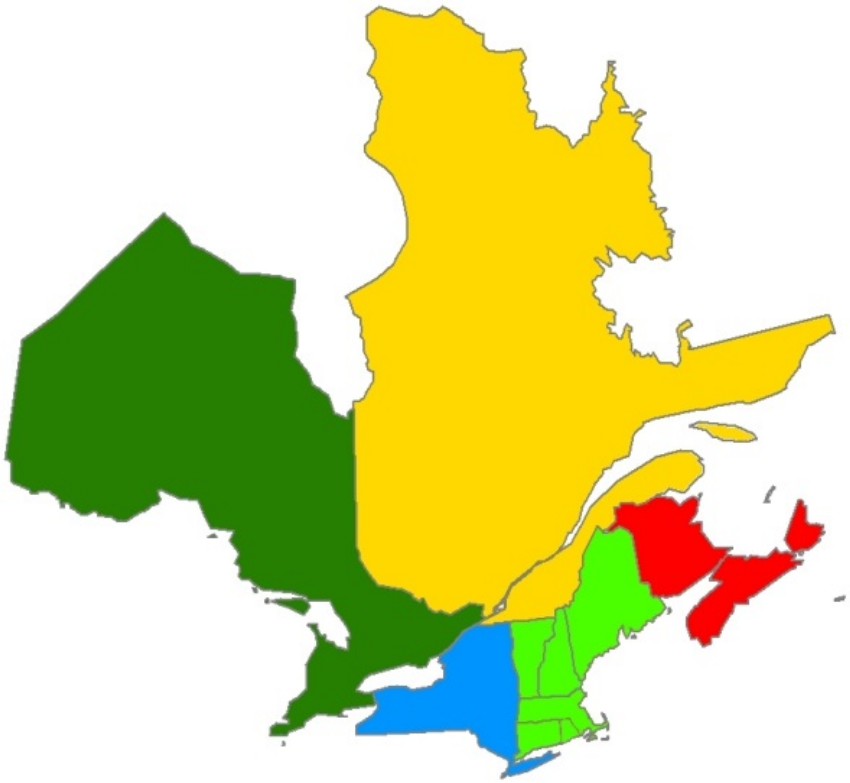
NERC – Lessons Learned (via email)	WECC Event Analysis
Source of Lesson Learned:	Western Electric Coordinating Council
Lesson Learned #:	20190901
Date Published:	September 4, 2019
Category:	Communications

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.

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

Northeast Power Coordinating Council, Inc. (NPCC)

2020 Business Plan and Budget



Draft #1
Submitted to NERC May 1, 2019

Table of Contents

Introduction 3
Personnel Analysis 12
Section A — 2020 Regional Entity Division Business Plan and Budget 15
Reliability Standards Program 15
Compliance Monitoring and Enforcement and Organization Registration and Certification Program 20
Reliability Assessment and Performance Analysis Program 26
Training, Education, and Operator Certification Program 34
Situation Awareness and Infrastructure Security Program 38
Administrative Services 45
Technical Committees and Member Forums 47
General and Administrative 48
Legal and Regulatory 49
Information Technology 50
Human Resources 52
Accounting and Finance 53
Regional Entity Assessment Analysis 54
Section B – Supplemental Financial Information 58
Reserve Balance 58
Breakdown by Statement of Activity Sections 59
Section C — Criteria Services Division Activities 66
Personnel Analysis 74
Reserve Analysis 2019 - 2020 75
Section D — Additional Financial Statements 77
Statement of Financial Position 77
Appendix A Staff Allocations 80
Appendix B Acronyms 82
Appendix C Index of Figures and Tables 84

Introduction

Total NPCC Resources (in whole dollars)	2020 Budget	U.S.	Canada	Mexico
Regional Entity Division FTEs	41.09			
Criteria Services Division FTEs	2.16			
Total FTEs	**43.25**			
Regional Entity Division Expenses	$16,431,647			
Criteria Services Division Expenses	$1,118,668			
Total Expenses	**$17,550,315**			
Regional Entity Division Inc(Dec) in Fixed Assets	**$170,000**			
Criteria Services Division Inc(Dec) in Fixed Assets	**$30,000**			
Total Inc(Dec) in Fixed Assets	**$200,000**			
Regional Entity Division Working Capital Requirement**	**($1,019,611)**			
Criteria Services Division Working Capital Requirement***	**($79,265)**			
Total Working Capital Requirement	**($1,098,876)**			
Total Regional Entity Division Funding Requirement	$15,582,037			
Total Criteria Services Division Funding Requirement	$1,069,402			
Total Funding Requirement	**$16,651,439**			
Regional Entity Division Assessments	**$15,338,737**	$XXX,XXX	$XXX,XXX	
Regional Entity Division Assessments Percentage	**100%**	XX.X%	XX.X%	
Criteria Services Division Membership Fees	**$1,065,202**	$XXX,XXX	$XXX,XXX	
Total NPCC Assessments & Membership Fees	**$16,403,939**	$XXX,XXX	$XXX,XXX	
NEL	XX	XX	XX	
NEL %	100%	XX.XX%	XX.XX%	

** Refer to Table B-1 on page 57 in Section B.
*** Refer to the Reserve Analysis on page 74 in Section C.

2020 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 to increase its total operating budget and assessments by 2.1% comprising a Regional Entity increase of 2.2% and a Criteria Services division increase of 0.6%. Additional 2020 succession implementation costs will be funded through existing Business Continuity Reserves, having no impact on assessments, and are excluded from the operating budget increase calculation. The proposed 2020 funding requirements will be satisfied by a Regional Entity division assessment of $15,338,737 and Criteria Services division fees of $1,065,202, for a total of $16,403,939. The total NPCC assessments and fees represent an increase of 2.1% compared to the 2019 total assessments and fees of $16,062,277. 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 46% U.S. and 54% 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 2020 targeted staffing level of 43.25 power industry professionals and support personnel. Details of the 2020 business plans and budget for each program area are included in Section A for the Regional Entity division. The 2020 Regional Entity division schedules are shown in Section B. Section C details the 2020 Criteria Services division business plan and budget.

Membership and Governance

NPCC monitors approximately 215 registered entities and some 448 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.

Under the Criteria Services division, NPCC will seek out and evaluate for membership, entities involved in emerging technologies to assure that those entities that have an impact on Bulk Electric System reliability are included in appropriate NPCC activities.

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 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 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.

2020 Key Goals and Key Deliverables

NERC and the Regional Entities collaborated in the development of a common operating model with complementary roles and responsibilities, an ERO Enterprise Long-term Strategy and an ERO Enterprise Operating Plan. Links to these documents, which incorporated risks identified by the Reliability Issues Steering Committee, are included in the NERC 2020 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. For example, key goals and deliverables within the Reliability Standards program area include supporting the development of risk-responsive Reliability Standards as well as facilitating a Distributed Energy Resources (DER) Forum. Within the Compliance Monitoring and Enforcement and Organization Registration and Certification program, in addition to conducting objective, risk-informed compliance monitoring, enforcement and entity registration activities, this area will be addressing increased enforcement activities and implementing the ERO Enterprise CMEP IT tool (Align). The Reliability Assessment and Performance Analysis program will be focusing on reduction of known risks to reliability and the identification and assessment of emerging reliability risks, such as changing resource composition. In the Situation Awareness and Infrastructure Security area there is an increasing focus on the identification and reduction of cyber and physical security risks through expanded outreach. In an order to achieve these goals and expanded efforts, while minimizing increases in budget, significant reprioritization within the business plan and reallocation of resources were required.

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 bulk 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, in conjunction with NERC and the other Regional Entities, has developed and deployed an ERO Enterprise-wide Compliance Monitoring and Enforcement IT tool (Align) for gathering data, analysis, and tracking of compliance information to carry out these responsibilities in a consistent and 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.

2020 Overview of Regional Entity Division Cost Impacts

The proposed Regional Entity division assessment of $15,338,737, to support the Regional Entity division operating budget of $16,157,107, is an increase of 2.2% compared to the 2019 assessment of $15,003,411.

2019 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. 2019 Projections reflect expectations based on the first quarter variance report. It is anticipated that projections could change throughout 2019 and would be reflected in each subsequent quarter's variance report.

Statement of Activities Format

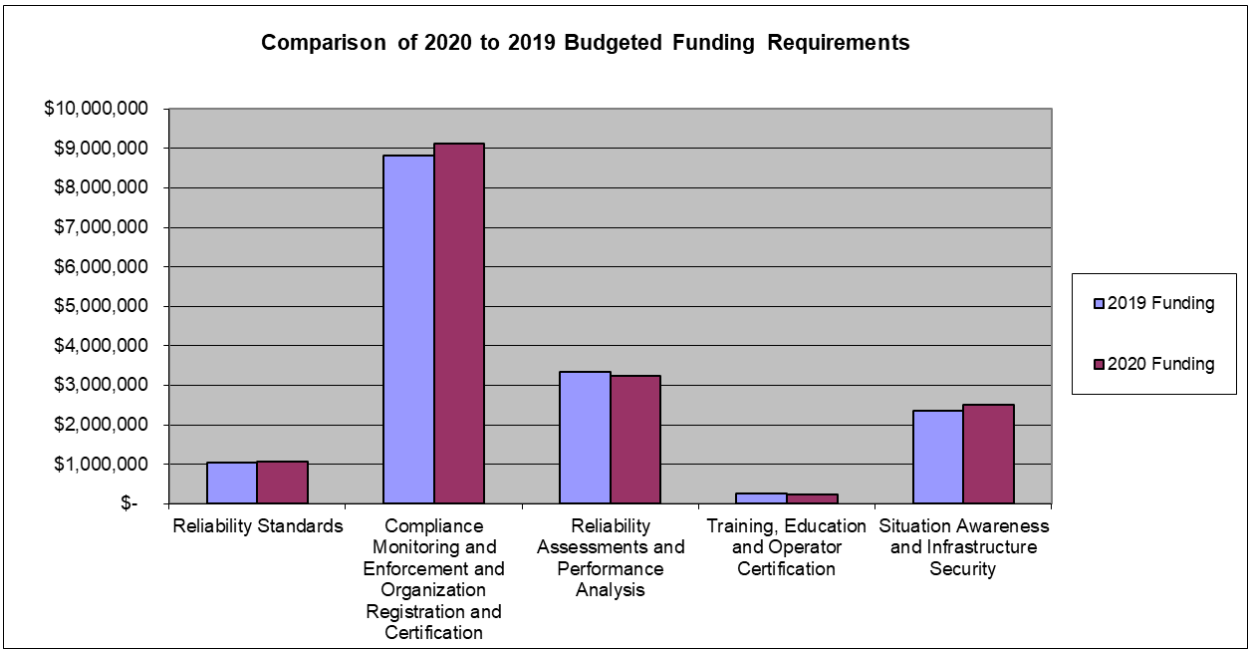
Beginning with the 2020 Business Plan & Budget (BP&B), NERC and the Regions are implementing format revisions to the Statement of Activities report. These revisions are intended to ensure that NERC and the Regions report information consistently from new accounting standards (e.g., leasing standards and right-of-use assets), provide enhanced transparency of financing activity (e.g., debt borrowing, leased-financed asset purchases, and principal payments), and streamline sections of the report related to non-cash expenses (primarily depreciation and amortization). The goal of the new format is to improve the effectiveness of the report to the reader and to provide a total budget amount that more closely reflects the amount of annual revenues required from assessments and other funding sources. One of the format revisions is that the Statements of Activities will no longer show an expense item for depreciation and an equal and offsetting credit for depreciation in fixed asset activity (which resulted in depreciation having no impact on funding requirements or actual results).

In the 2020 BP&B document, the 2019 budget has been restated to reflect the new statement of activities reporting format when comparing 2020 to 2019 to show the year-over-year budget changes on a comparable basis. As such, in the total entity and departmental Statements of Activities, depreciation expense has been removed from the 2019 operating expense budgets and projections, and an equal credit of depreciation expense has been removed from the 2019 fixed asset activity budgets and projections.

Summary by Program

Program	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Reliability Standards	$ 1,035,390	$ 1,035,390	$ 1,071,015	$ 35,625	3.4%
Compliance Monitoring and Enforcement and Organization Registration and Certification	$ 8,816,687	$ 8,671,687	$ 9,109,633	$ 292,946	3.3%
Reliability Assessments and Performance Analysis	$ 3,332,686	$ 3,332,686	$ 3,231,169	$ (101,517)	-3.0%
Training, Education and Operator Certification	$ 252,443	$ 252,443	$ 239,412	$ (13,031)	-5.2%
Situation Awareness and Infrastructure Security	$ 2,366,685	$ 2,366,685	$ 2,505,877	$ 139,192	5.9%
Total	$ 15,803,891	$ 15,658,891	$ 16,157,107	$ 353,216	2.2%

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 2019	Projection 2019	Direct FTEs 2020 Budget	Shared FTEs[1] 2020 Budget	Total FTEs 2020 Budget	Change from 2019 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	17.00	18.00	0.00	18.00	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	4.50	0.93	5.43	-0.40
Situation Awareness and Infrastructure Security	5.00	5.00	5.40	0.00	5.40	0.40
Total FTEs Operational Programs	**29.86**	**29.86**	**29.00**	**1.86**	**30.86**	**1.00**
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	0.23	2.73	0.23
Information Technology	2.00	2.00	2.00	0.00	2.00	0.00
Legal and Regulatory	1.00	1.00	2.00	0.00	2.00	1.00
Human Resources	1.00	1.00	1.00	0.00	1.00	0.00
Accounting and Finance	2.00	2.00	2.00	0.00	2.00	0.00
Total FTEs Administrative Programs	**9.00**	**9.00**	**10.00**	**0.23**	**10.23**	**1.23**
Total FTEs	**38.86**	**38.86**	**39.00**	**2.09**	**41.09**	**2.23**

[1]A shared FTE is defined as an employee who performs both Regional Entity and Criteria Services division functions.

2019 Budget and Projection and 2020 Budget Comparisons

Statement of Activities and Capital Expenditures
2019 Budget & Projection, and 2020 Budget

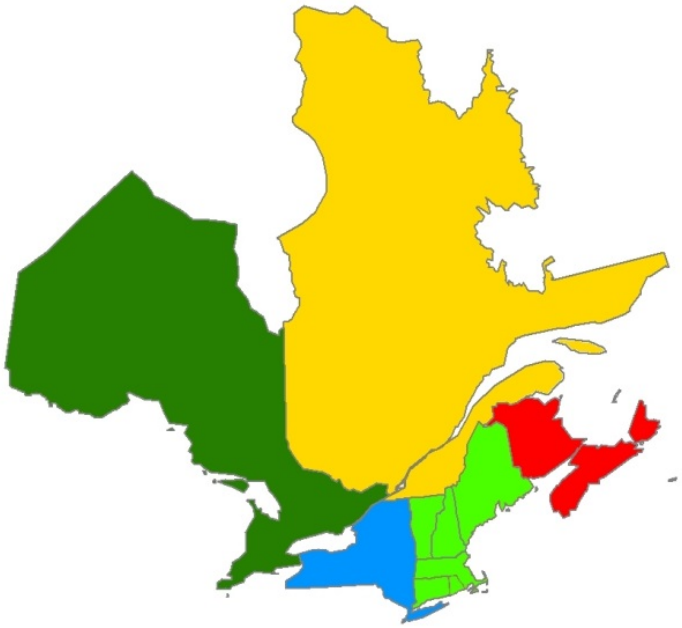
REGIONAL ENTITY DIVISION

		2019 Budget	2019 Projection	Variance[2] 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 15,003,411	$ 15,003,411	$ -	$ 15,338,737	$ 335,326
	Penalty Sanctions[1]	-	-	-	120,000	120,000
Total ERO Funding		**$ 15,003,411**	**$ 15,003,411**	**$ -**	**$ 15,458,737**	**$ 455,326**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	67,500	67,500	-	67,500	-
	Interest & Investment Income	-	-	-	55,800	55,800
Total Funding (A)		**$ 15,070,911**	**$ 15,070,911**	**$ -**	**$ 15,582,037**	**$ 511,126**
Expenses						
Personnel Expenses						
	Salaries	$ 7,332,280	$ 7,216,280	$ (116,000)	$ 7,704,262	$ 371,982
	Payroll Taxes	449,994	444,994	(5,000)	479,019	29,026
	Benefits	1,613,078	1,585,078	(28,000)	1,943,385	330,306
	Retirement Costs	853,511	837,511	(16,000)	882,950	29,440
Total Personnel Expenses		**$ 10,248,862**	**$ 10,083,862**	**$ (165,000)**	**$ 11,009,617**	**$ 760,754**
Meeting Expenses						
	Meetings & Conference Calls	$ 370,750	$ 406,750	$ -	$ 397,750	$ (9,000)
	Travel	845,900	845,900	-	845,900	-
Total Meeting Expenses		**$ 1,252,650**	**$ 1,252,650**	**$ -**	**$ 1,243,650**	**$ (9,000)**
Operating Expenses						
	Consultants & Contracts	$ 2,022,150	$ 2,002,150	$ (20,000)	$ 2,071,150	$ 49,000
	Office Rent	820,700	820,700	-	832,700	12,000
	Office Costs	676,347	676,347	-	685,981	9,634
	Professional Services	978,000	978,000	-	947,000	(31,000)
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	51,000	51,000	-	51,000	-
Total Operating Expenses		**$ 4,548,197**	**$ 4,528,197**	**$ (20,000)**	**$ 4,587,831**	**$ 39,634**
	Total Direct Expenses	**$ 16,049,709**	**$ 15,864,709**	**$ (185,000)**	**$ 16,841,098**	**$ 791,388**
Indirect Expenses		**$ (415,818)**	**$ (415,818)**	**$ -**	**$ (409,450)**	**$ 6,368**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 15,633,891**	**$ 15,448,891**	**$ (185,000)**	**$ 16,431,647**	**$ 797,756**
Change in Assets		**$ (562,980)**	**$ (377,980)**	**$ 185,000**	**$ (849,611)**	**$ (286,630)**
Fixed Asset Additions (C)		**$ 170,000**	**$ 170,000**	**$ -**	**$ 170,000**	**$ -**
TOTAL BUDGET (=B+C)		**$ 15,803,891**	**$ 15,618,891**	**$ (185,000)**	**$ 16,601,647**	**$ 797,756**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (732,980)**	**$ (547,980)**	**$ 185,000**	**$ (1,019,611)**	**$ (286,630)**

[1] $120,000 of penalty sanctions collected to date and prior to June 30, 2019.

[2] 2019 Projections reflect expectations based on the first quarter statement of activities. It is anticipated that projections could change throughout 2019 and would be reflected in each subsequent quarter's statement of activities.

Section A – Regional Entity Division
2020 Business Plan and Budget



Section A — 2020 Regional Entity Division Business Plan and Budget

Reliability Standards Program

Reliability Standards Program Resources (in whole dollars)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	1.93	1.93	0.00
Direct Expenses	$665,870	$693,683	$27,813
Indirect Expenses	$359,634	$366,700	$7,066
Other Non-Operating Expenses	$0	$0	$0
Fixed Asset Additions	$10,988	$10,632	($356)
Total Funding Requirement	$1,036,492	$1,071,015	$34,523

Program Scope and Functional Description

The NPCC Reliability Standards Program Area operates in accordance with NPCC's filed and approved Regional Delegation Agreement and NERC Rules of Procedure Section 300. The program supports the ERO Standards Program Area roles and responsibilities, the ERO Enterprise Operating Plan, the ERO Enterprise Long-Term Strategy and aligns with NPCC Board of Director goals and strategies. NPCC's Reliability Standards Program Area provides an efficient and effective mechanism for stakeholders to provide input and facilitate the development of, and improvement to, NERC and Regional 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 and Regional variances which establish "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 also responsive to FERC Directives and industry risk. NERC and Regional reliability standards must ensure the bulk electric system is planned, operated, and maintained in a manner that minimizes risks of cascading failures, system separation, and instability, and also 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, and ERO Standards Variances for the northeast as required. The NPCC Reliability Standards Program Area also provides oversight to ensure that NPCC's Regional Reliability Criteria contained in the form of Directories, are developed, approved, and maintained as necessary to implement, to augment, or to facilitate compliance with NERC Reliability Standards. NPCC's reliability criteria are not reliability standards but are mandatory and subject to enforcement as outlined in the NPCC *Amended and Restated Bylaws* and various ISO tariffs, and individual interconnection agreements, as well as other executed contractual agreements. Regional Reliability Criteria may also address issues not within NERC's statutory jurisdiction for Reliability Standards, such as resource adequacy, and conform to requirements in Section 313 of the NERC Rules of Procedure.

In addition, the NPCC Reliability Standards Program Area has initiated a Distributed Energy Resources (DER) Forum. As conventional fossil fuel units and nuclear retirements are increasingly being replaced by DER on the transmission system and with grid edge DER on the

distribution system, the reliable operation of the BES as defined in the legislation could be impacted. The control systems of DER introduce new capabilities that could enhance reliability and understanding interoperability issues between transmission and distribution systems will become increasingly important. NPCC is engaged in a number of areas to ensure reliable integration into the BES and opportunities to provide industry guidance for interconnecting DER.

2020 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 acting on recommendations of the various phases of the Standards Efficiency Review project, conducting periodic reviews on existing Reliability Standards to improve their content and quality, responding to identified risks to reliability (including those that may be identified through the implementation of risk-based Compliance Monitoring and Enforcement), and addressing 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 NERC Reliability Standards, NPCC's Regional Reliability Standard for Underfrequency Load Shedding "UFLS" 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 further 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 at a stable level, driven by requests that the Regional Entity may receive or reliability issues that are identified and not under consideration by NERC. Creation of Variances to NERC Reliability Standards to address reliability concerns or to recognize the unique topology and reliability considerations of the Northeast (i.e. Québec's recognition of an asynchronous interconnection within NPCC's footprint) will be performed as necessary.
- The number of NERC and Regional standards interpretations is expected to remain low. Compliance Implementation Guidance documents, which provide approaches to being compliant with NERC Reliability Standards may be developed using NPCC's open process and other industry vetting practices. These guidance documents are currently being developed by industry and the Standard Drafting Teams and the number of 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 redundancy to the ERO standards.

2020 Goals and Key Deliverables

- Participate in the annual development and revision of the NERC's 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, support ERO efforts to address outstanding FERC Directives, and provide input in the prioritization of standards development projects.
- Support further development of cost effectiveness principles processes 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 NERC Standards Efficiency Review Project future phases and resulting activities.
- Participate in the development of ERO Reliability Standards specified in NERC's three-year Reliability Standards Development 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 under development or revision by leveraging existing NPCC Task Forces and subject matter experts and coordinate NPCC comments for Northeastern North America.
- Participate in the Enhanced Periodic Review Standing Team's grading efforts and coordinate and represent the Regional and interregional input.
- Assist NERC's review of all industry "Requests for Interpretations" of NERC Reliability Standards.
- NPCC staff and Regional drafting team volunteers will participate in the drafting of ERO standards and provide support for development of improvements to standards. Those chosen to participate in drafting of standards will provide a point of contact for the NPCC Regional input to the standard being developed.
- NPCC and its members will review and coordinate 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.
- 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 when requested.
- Monitor the NERC Reliability Issues Steering Committee "RISC" activities as they identify emerging risks and develop recommended actions to mitigate such risks. 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), Geomagnetic Disturbances, High

Altitude Electromagnetic Pulse (HEMP), changes to standards driven by inverter based DERs, etc.

- Identify opportunities and initiate Regional Variances to the NERC Reliability Standards as soon as possible, allowing incorporation into the continent wide standard during the development process.
- Conduct 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.
- Identify potential reliability benefits and impacts to the BES as a result of DER penetration.
- Conduct ongoing DER Forum activities to solicit and identify both opportunities and challenges to enhancing reliability through education, promotion of awareness and developing guidance, particularly for interconnection of utility scale DER on the Distribution System.
- Identify opportunities to improve resilience of the BES.
- Identify and coordinate reliability related issues with local governmental authorities where jurisdictional issues may exist.
- Ensure the topics addressed by the Reliability Standards align with changing industry and reliability objectives.
- Participate in reliability metrics developmental 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 Review Team activities.
- Identify opportunities and processes for cost-effectiveness analysis activities to determine the need to revise a standard during the Periodic Review or Standards Grading efforts.
- Identify any emerging interconnection-wide reliability issues which may need standards solutions and forward to the NERC Reliability Issues Steering Committee for their consideration.
- Identify opportunities to increase reliability or mitigate emerging risk through the revision of standards and their associated requirements.
- Identify any North American Electric Standards Review Board (NAESB) activities which may impact ERO standards.
- Identify potential market related issues for Regional Standards through NPCC RSC coordination and reviews.
- Participate in NPCC Compliance and Standards Workshops and any NERC workshops and webinars to promote industry awareness.

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

- No significant changes.

Reliability Standards Program

Funding sources and related expenses for the Reliability Standards section of the 2019 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 2019 Budget & Projection, and 2020 Budget						
Reliability Standards						
		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 1,035,390	$ 1,035,390	$ -	$ 1,063,510	$ 28,120
	Penalty Sanctions	-	-	-	7,505	7,505
Total ERO Funding		**$ 1,035,390**	**$ 1,035,390**	**$ -**	**$ 1,071,015**	**$ 35,625**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 1,035,390**	**$ 1,035,390**	**$ -**	**$ 1,071,015**	**$ 35,625**
Expenses						
Personnel Expenses						
	Salaries	$ 382,872	$ 382,872	$ -	$ 400,744	$ 17,872
	Payroll Taxes	22,735	22,735	-	23,034	298
	Benefits	106,764	106,764	-	110,172	3,408
	Retirement Costs	41,599	41,599	-	43,833	2,234
Total Personnel Expenses		**$ 553,970**	**$ 553,970**	**$ -**	**$ 577,783**	**$ 23,813**
Meeting Expenses						
	Meetings & Conference Calls	$ 7,000	$ 7,000	$ -	$ 5,000	$ (2,000)
	Travel	94,900	94,900	-	90,900	(4,000)
Total Meeting Expenses		**$ 101,900**	**$ 101,900**	**$ -**	**$ 95,900**	**$ (6,000)**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 10,000	$ 10,000	$ -	$ 20,000	$ 10,000
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Operating Expenses		**$ 10,000**	**$ 10,000**	**$ -**	**$ 20,000**	**$ 10,000**
	Total Direct Expenses	**$ 665,870**	**$ 665,870**	**$ -**	**$ 693,683**	**$ 27,813**
Indirect Expenses		**$ 375,014**	**$ 375,014**	**$ -**	**$ 366,700**	**$ (8,313)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 1,040,884**	**$ 1,040,884**	**$ -**	**$ 1,060,383**	**$ 19,499**
Change in Assets		**$ (5,494)**	**$ (5,494)**	**$ -**	**$ 10,632**	**$ 16,126**
Fixed Asset Additions (C)		**(5,494)**	**(5,494)**	**-**	**10,632**	**16,126**
TOTAL BUDGET (=B+C)		**$ 1,035,390**	**$ 1,035,390**	**$ -**	**$ 1,071,015**	**$ 35,625**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (0)**	**$ (0)**	**$ -**	**$ 0**	**$ 0**

Compliance Monitoring and Enforcement and Organization Registration and Certification Program

Compliance Monitoring and Enforcement and Organization Registration and Certification Program Resources (in whole dollars)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	17.00	18.00	1.00
Direct Expenses	$5,561,849	$5,590,473	$28,624
Indirect Expenses	$3,167,761	$3,420,003	$252,241
Other Non-Operating Expenses	$0	$0	$0
Fixed Asset Additions	$96,785	$99,157	$2,372
Total Funding Requirement	$8,826,396	$9,109,633	$283,237

Program Scope and Functional Description

The NPCC Compliance Monitoring and Enforcement and Organization Registration and Certification Program (CORC) Program Area operates in accordance with NPCC's filed and approved Regional Delegation Agreement, the NERC Rules of Procedure, and individual Canadian Provincial MOUs and/or Agreements. The program supports Compliance Enforcement (Section 400) and Organization Registration and Certification (Section 500), the ERO Enterprise Operating Plan, the ERO Enterprise Long-Term Strategy, and aligns with NPCC Board of Director goals and strategies.

The CORC Program Area 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) IT Tool (Align) in the United States, including the compliance monitoring, assessment and enforcement of NERC Reliability Standards and Regional Reliability Standards;
3) In accordance with the relevant memorandums of understanding (MOU's), the implementation of the risk-based NERC CMEP in Ontario and Nova Scotia, including the assessment and enforcement of NERC Reliability Standards and Regional Reliability Standards effective in those jurisdictions,
4) The implementation of the Québec Reliability Standards Compliance Monitoring and Enforcement Program (QCMEP), including the compliance monitoring, assessment and enforcement of NERC Reliability Standards and Regional Reliability Standards effective in Quebec, and
5) The implementation of the New Brunswick Compliance Monitoring and Enforcement Program (NBCMEP) in New Brunswick, including the compliance monitoring, assessment and enforcement recommendations of the NERC Reliability Standards and Regional Reliability Standards effective in New Brunswick.

Through the CORC Program Area, NPCC strives to be a strong enforcement authority that is objective, fair, and promotes a culture of reliability excellence through risk-informed compliance monitoring, mitigation, enforcement, and registration. To accomplish this goal, CORC is

divided into three sub-program areas: Compliance Fundamentals; Compliance Audits and Investigations; and Compliance Mitigation and Enforcement.

Compliance Fundamentals

The Compliance Fundamentals sub-program area is responsible for registration and certification activities and for general compliance activities that span across the other three sub-program areas. The Compliance Fundamentals sub-program area:

- Identifies and registers the BES owners, operators, and users that are required to comply with the NERC and Regional Reliability Standards,
- Conducts Certifications in accordance with the NERC ROP,
- Leads the development of the annual implementation plans (ERO Enterprise, NPCC, Quebec, New Brunswick),
- Implements the ERO Enterprise CMEP IT tool (Align),
- Responds to any Complaints submitted to NPCC,
- Maintains any NPCC specific compliance tools or programs needed, and;
- Conducts outreach, training, and education to support the implementation of Reliability Standards.
- Conducts Inherent Risk Assessments (IRA) on registered entities,
- Conducts Internal Controls Evaluations (ICE) on volunteering registered entities,
- Assists with the development of the annual CMEP implementation plans, and;
- Provides the basis for each registered entity's Compliance Oversight Plan.

Compliance Audits and Investigations

The Compliance Audits and Investigations sub-program area is responsible for conducting all compliance monitoring activities. The Compliance Audits and Investigations sub-program area is focused on the most significant risks to the BPS. The Compliance Audits and Investigations sub-program area:

- Conducts NPCC compliance monitoring activities, including audits, spot checks, and guided self-certifications,
- Incorporates the results of the IRA and ICE into its compliance monitoring process,
- Issues reports, including audit reports, spot check reports, guided self-certification reports, and;
- Implements and maintains the Critical Infrastructure Protection (CIP) Standards Technical Feasibility Exceptions process.

Compliance Mitigation and Enforcement

The Compliance Mitigation and Enforcement sub-program area is responsible for undertaking enforcement activities in accordance with risk-based approaches and conducting technical assessments of registered entities' plans and activities to mitigate noncompliance. Depending on the jurisdiction, enforcement either makes official recommendations to the appropriate regulatory authority or assists and coordinates with NERC to make such official recommendations. The Compliance Mitigation and Enforcement sub-program area:

- Determines the relevant facts and circumstances necessary to understand each noncompliance,
- Evaluates and assigns a risk level to each noncompliance,
- Evaluates and approves the mitigation activities or Mitigation Plan for each noncompliance,
- Assesses the relevant compliance history for each noncompliance,
- Determines the disposition method for each noncompliance,

- Calculates penalty sanctions in consistent fashion, and
- Evaluates registered entities for the self-logging program.

2020 Key Assumptions and Cost Impacts

2019	Projected 2020
5 On-Site Audits	8 On-Site O&P Audits
8 On-Site CIP Audits	10 On-Site CIP Audits
28 Off-Site Audits	40 Off-Site O&P Audits
24 Off-Site CIP Audits	25 Off-Site CIP Audits
15 Spot Checks	10 Spot Checks
18 Guided self-certifications	40 Self-certifications
33 Inherent Risk Assessments	50 Inherent Risk Assessments
4 On-site O&P Internal Control Evaluations	7 On-site O&P Internal Control Evaluations
5 On-site CIP Internal Control Evaluations	10 On-Site CIP Internal Control Evaluations
216 Violations (Estimated)	225 Violations (Estimated)
Settlements Covering 50 Violations	Settlements Covering 80 Violations
0 Hearings (Unbudgeted)	1 Hearings (Unbudgeted)
1 CI (Estimated)	1 CI (Estimated)
3 Entity Certifications	2 Entity Certifications

- Compliance Monitoring activities are projected to increase in 2020 from 2019 and will be cost effectively addressed with the addition of one FTE on the compliance staff, which is offset by a decrease in contract audit costs.
- The 2020 Business Plan projects increases in Enforcement Processing activities over the 2019 Budget. It is expected that the increase in violation processing will continue in 2021. This is partly due to the increase in the number of cyber systems that are in scope for compliance in most jurisdictions.
- One Compliance Investigation is projected for 2020. Compliance Investigations are manpower intensive for NPCC staff (requiring allocation of more resources and potentially higher than normal costs).

2020 Goals and Key Deliverables

- Conduct scheduled compliance monitoring and enforcement activities pursuant to the 2020 Implementation Plans.
- Continue applying risk-based approaches for CMEP, registration, and certification activities.
- Identify potential issues related to NERC Reliability Standards as a result of compliance monitoring, enforcement and event analysis activities.
- Continue to implement compliance responsibilities in Canada based on the unique regulatory structure specific to each provincial and/or governmental jurisdiction.
- Evaluate monitoring, violation processing, risk-assessment, registration and certification program for sufficiency and effectiveness. Modify as needed.
- Collaborate within the ERO Enterprise to develop and implement a common and consistent CMEP IT tool (Align) for compliance processes, information systems, and methods among Regions.

- Provide education and outreach to the registered entities on all CMEP, registration, and certification topics, including the development and implementation of the ERO Enterprise Registration and CMEP software reporting systems and tools.
- Conduct two in-person Compliance Workshops.
- Develop annual reports for QCMEP/CMEP activity in Québec and New Brunswick.
- Develop and/or provide input on 2020 CMEP Implementation Plans (ERO Enterprise, NPCC, Québec, New Brunswick).
- Attend training necessary and/or beneficial to performing Registration, Certification, Entity Risk Assessment, Monitoring, and Enforcement activities.
- Assure that NPCC staff is appropriately trained to conduct Certification and Auditing activities.
- Provide detailed responses to oversight activity performed by NERC, FERC, and other relevant authorities.
- Continue to perform and update IRAs for registered entities.
- Continue to perform an ICE for registered entities that volunteer for such an assessment.
- Continue to assess internal controls during monitoring engagements
- Conduct 2020 Compliance Engagement Schedule based on risk to the BPS 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 updated Inherent Risk Assessment as necessary for all scheduled engagements and performing an Internal Controls Evaluation for all entities that volunteer.
- Continue to perform comprehensive enforcement investigations to determine the relevant facts and circumstances necessary to understand each noncompliance, assess the risk, and evaluate the mitigation activities or Mitigation Plan for each noncompliance. Determine the disposition method in accordance with established risk-based approaches (i.e. Compliance Exceptions, FFTs, Simplified Identification Correction Method (Québec), Settlements, etc.)
- Evaluate the mitigation activities or Mitigation Plan for each noncompliance, track the progress and verify the completion of each Mitigation Plan.
- As necessary, represent NPCC during any enforcement hearings before the NPCC Hearing Body, the NERC Hearing Body, the Régie, or the NBEUB.
- Evaluate registered entities for the self-logging program.
- Analyze noncompliance trends and associated risks in order to develop guidance to registered entities in support of a culture of reliability.
- Perform outreach (webinars, workshops) to educate entities on noncompliance root causes and on techniques for noncompliance assessment and communication associated with self-reporting to NPCC; including the provision of guidance on the development of mitigation activities that will prevent recurrence.
- Assess evolving cyber security risks for opportunities to develop internal control flow diagrams in order to provide entity guidance

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 56% of its resources on this activity.

Resource Requirements

Personnel

- One additional FTE to increase in-house expertise rather than utilizing contractor labor. The increase in personnel expenses will be offset by a decrease in Consultants and Contracts.

Fixed Assets

- No new functionality is planned for the Compliance Issues Tracking System and CMEP Data Administration Application at this time based on the planned implementation of the ERO Enterprise CMEP IT Tool (Align).

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 2020 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
2019 Budget & Projection, and 2020 Budget
Compliance Monitoring and Enforcement and Organization Registration and Certification

		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 8,183,815	$ 8,183,815	$ -	$ 9,002,624	$ 818,809
	Penalty Sanctions	-	-	-	69,994	69,994
Total ERO Funding		**$ 8,183,815**	**$ 8,183,815**	**$ -**	**$ 9,072,617**	**$ 888,802**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 8,183,815**	**$ 8,183,815**	**$ -**	**$ 9,072,617**	**$ 888,802**
Expenses						
Personnel Expenses						
	Salaries	$ 2,815,882	$ 2,720,882	$ (95,000)	$ 2,928,438	$ 112,557
	Payroll Taxes	191,849	188,849	(3,000)	202,717	10,867
	Benefits	585,543	572,543	(13,000)	732,104	146,561
	Retirement Costs	301,025	287,025	(14,000)	314,664	13,638
Total Personnel Expenses		**$ 3,894,299**	**$ 3,769,299**	**$ (125,000)**	**$ 4,177,923**	**$ 283,624**
Meeting Expenses						
	Meetings & Conference Calls	$ 15,000	$ 15,000	$ -	$ 15,000	$ -
	Travel	295,400	295,400	-	300,400	5,000
Total Meeting Expenses		**$ 310,400**	**$ 310,400**	**$ -**	**$ 315,400**	**$ 5,000**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 1,357,150	$ 1,337,150	$ (20,000)	$ 1,097,150	$ (260,000)
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Operating Expenses		**$ 1,357,150**	**$ 1,337,150**	**$ (20,000)**	**$ 1,097,150**	**$ (260,000)**
	Total Direct Expenses	**$ 5,561,849**	**$ 5,416,849**	**$ (145,000)**	**$ 5,590,473**	**$ 28,624**
Indirect Expenses		**$ 3,303,230**	**$ 3,303,230**	**$ -**	**$ 3,420,003**	**$ 116,772**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 8,865,080**	**$ 8,720,080**	**$ (145,000)**	**$ 9,010,476**	**$ 145,396**
Change in Assets		**$ (681,264)**	**$ (536,264)**	**$ 145,000**	**$ 62,141**	**$ 743,406**
Fixed Asset Additions (C)		**$ (48,392)**	**$ (48,392)**	**$ -**	**$ 99,157**	**$ 147,550**
TOTAL BUDGET (=B+C)		**$ 8,816,687**	**$ 8,671,687**	**$ (145,000)**	**$ 9,109,633**	**$ 292,946**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (632,872)**	**$ (487,872)**	**$ 145,000**	**$ (37,016)**	**$ 595,856**

Reliability Assessment and Performance Analysis Program

Reliability Assessment and Performance Analysis Program Resources (in whole dollars)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	5.83	5.43	-0.40
Direct Expenses	$2,216,468	$2,169,556	($46,912)
Indirect Expenses	$1,086,356	$1,031,701	($54,655)
Other Non-Operating Expenses	$0	$0	$0
Fixed Asset Additions	$33,192	$29,913	($3,279)
Total Funding Requirement	$3,336,016	$3,231,169	($104,847)

Program Scope and Functional Description

NPCC, through its top technical committee, the Reliability Coordinating Committee (RCC), integrates the deliverables of its Task Forces' and Working Groups' Reliability Assessment and Performance Analysis (RAPA) related activities.

Seasonal assessments of the overall NPCC resource adequacy 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 criteria 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.

2020 Key Focus Areas

In collaboration with NERC, Key Focus Area activities for 2020 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.
- 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 ERO activities to identify key reliability risks and appropriate projects designed to enhance reliability and/or mitigate risks.
- Providing technical resources to support NERC special reliability assessments which focus on specific reliability risk areas in geographic areas with specific identified reliability concerns.
- Advancing analytical capabilities for identifying and determining reliability risks and conducting associated related reliability assessments.

Eastern Interconnection Reliability Assessment Group (ERAG)

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 Committee. These assessment-related activities support ERO Goal 3: "*Reduction of Known Risks to Reliability*" and 4 "*Identification and Assessment of Emerging Reliability Risks*."

NPCC RAPA staff participates with the ERAG Committee as one of the four Eastern Interconnection Regional Entities, and acts as the liaison between the ERAG MMWG and the NPCC SS-37 Working Group.

ERAG Committee Activities 2020 Goals and Deliverables

- Transition the steady state and dynamic simulation base case data compilation and development work from ERAG to the Eastern Interconnection Planning Collaborative (EIPC).
- Support EIPC designation and certification as the Eastern Interconnection MOD-032, Requirement R4 Designee.
- During a transition period oversee the steady state and dynamic simulation base case data compilation and development.
- Oversee the ERAG assessment plan and coordinate assessment efforts with NERC Assessment Program staff. Determine the targeted ERAG assessment topic for 2020. Determine to method of assessment: analytical study, research effort, peer review.
- Make appropriate revisions, as necessary, to the ERAG Strategic Direction (i.e. anticipated new developments in MMWG process and system assessments).
- Develop and approve the ERAG activity budgets.

Multi-Regional Modeling Working Group 2020 Goals and Deliverables

- During a transition period of the Eastern Interconnection base case development MOD-032-1, Requirement 4 Designee period from ERAG to EIPC facilitate the completion of the steady state and dynamic simulation base case data compilation and development for the 2020 series of cases.
- Check and confirm that the dynamic model data passes all applicable checks and acceptance criteria.
- Incorporate dispatch information into the future and seasonal MMWG base cases so that the dispatches are more closely aligned with economic dispatch practices.
- Continue to improve the representations of the governor-turbine plant control models.
- 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.

ERAG System Assessments 2020 Goals and Deliverables

- Determine an appropriate topic of focus for the 2020 ERAG Assessment. In recent years, ERAG has conducted peer reviews on select topics in lieu of conducting assessments. Conduct the 2020 ERAG Assessment and prepare any associated documentation.
- 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.

Bulk Electric System Notification and Exception (BESnet) application and Exception Request (ERs)

NPCC supports maintenance of the BESnet application and the processing of the Regional BES Exception Requests (ERs), including periodic certifications that the basis for an Element being included or excluded in the BES through the Exception remains valid. No NPCC Exception Requests are due for recertification in 2020. Analysis of an Exception Request from a New Brunswick entity may extend into 2020.

2020 NERC Activities

NPCC will provide the Regional perspective with appropriate NPCC RAPA staff participation on selective NERC Technical Committees and key related NERC Subcommittees, Task Forces and Working Groups, including:

- Event Analysis Subcommittee (EAS)
- Inverter-Based Resource Performance Task Force (IRPTF)
- Performance Analysis Subcommittee (PAS)
  - Demand Response Availability Data System Working Group (DADSWG)
  - Battery Availability Data System Working Group (BADSWG)
  - Generating Availability Data System Working Group (GADSWG)
  - Misoperation Information Data Analysis System (MIDASWG)
  - Transmission Availability Data System Working Group (TADSWG)
- Reliability Assessment Subcommittee (RAS)
  - Probabilistic Assessment Working Group (PAWG)
- System Analysis and Modeling Subcommittee (SAMS)
  - Load Modeling Task Force (LMTF)
  - Power Plant Model Verification Task Force (PPMVTF)
  - Node Breaker Modeling Group (NBMG)
- System Protection and Control Subcommittee (SPCS)
- Synchronized Measurement Subcommittee (SMS)
- System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG)
- Battery and Storage Task Force (BASTF)

ERO – Executive Management Group (EMG) 2020 Activities

Provide analytic support for the ERO-EMG:

- Operations Leadership Team;
- Bulk Electric System Exception Process Working Group, under Organization Registration and Certification Group (ORCG);
- ERO-RAPA Group; and,
- Other activities as directed by the ERO-Executive Management Group.

2020 Goals and Key Deliverables

NPCC Task Force activities support 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.*"

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.

TFCP Reliability Assessment and Performance Analysis 2020 Goals and Deliverables

- Coordinate NPCC responses to the approved 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 the recommendations are addressed.
- Coordinate the development of additional NPCC Criteria as necessary and track any new and developing Regional NPCC Standards through the NPCC Regional Standards Committee.
- Monitor industry practices and make recommendations to the NPCC Regional Standards Committee regarding related NERC Standards.
- Oversee the NPCC Directory No. 1 Implementation Plan (Dated: September 30, 2015).
- Oversee the activities of the NPCC CP-8 Working Group.
- Evaluate and recommend RCC approval of NPCC Area Transmission Reviews.
- Evaluate and recommend RCC approval of NPCC Area Reviews of Resource Adequacy.
- Coordinate, monitor, review, and make recommendations on the retirement of existing in-service and/or implementation of proposed or modified Special Protection Systems Remedial Action Schemes.
- Coordinate the NPCC transition from SPS to RAS in accordance with PRC-012-2.
-
- Lead the NPCC Task Forces in conducting the review of the reliability and cost benefit of Directory No. 1, Design and Operation of the BPS.
- Support related reliability activities, including consideration of any requests for sub-regional assessments.
- Keep informed on studies and developments in neighboring systems which might impact NPCC reliability.
- 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 related NPCC documents.

TFSS Reliability Assessment and Performance Analysis 2020 Goals and Deliverables

- Review and recommend approval of Area Transmission Reviews.
- Review and classify new and modified Remedial Action Schemes.
- Review and Implement the NPCC A-10 Criteria.
- Perform annual review and update of the Major Project List.
- 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 Bulk Electric System risks as identified by the NERC Reliability Issues Steering Committee.

- Review existing NPCC Regional Criteria and procedures for validation of data used in power flow and dynamic simulations; propose changes to provide for adequate data validation.
- Perform investigation of Distributed Energy Resources modeling practices.
- Annually develop a library of power flow base cases and associated dynamic cases.
- Enable the annual review of the NPCC event replication procedure and ensure the preparedness of the NPCC Planning Coordinators to develop base cases for a required investigation of a major system event in or affecting NPCC and support the performance of event replication by benchmarking simulations against actual system performance.
- Work with software vendors and NERC to enhance the capability for dynamic simulations.
- Continue to investigate the use of dynamic load models for transient stability studies.
- Investigate the use of load monitoring equipment to aid in the benchmarking of dynamic load models used in transient stability studies.

Task Force on System Protection

The primary 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 NPCC protection systems.

TFSP Reliability Assessment and Performance Analysis 2020 Goals and Deliverables

- Assess proposed protection systems and Special Protection Systems/Remedial Action Schemes.
- Participate and/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.
- Participate in the ongoing development and submission of NPCC inputs/comments into the development of related NERC Reliability Standards.
- Monitor the NPCC metric on protection system Misoperation Risk Index Score calculations.
- Review mitigations and/or progress reports for Bulk Power System Risk Reduction Implementation.
- Provide support and technical input for related protection system risks as identified by the NERC Reliability Issues Steering Committee.
- Conduct review/development of related NPCC Directories.
- Consistent with the TFSP's scope, conduct joint meeting with other Regions to share best practices and experiences.
- Review ongoing changes to the North American Reliability Corporation Critical Infrastructure Protection Standards and evaluate impacts to Registered Entities Protection Systems, SCADA, and Monitoring Systems.

Task Force on Coordination of Operation

The NPCC Task Force on Coordination of Operation (TFCO) primarily facilitates the coordination of operations among the NPCC Reliability Coordinator areas and adjacent NERC Regions to enhance the reliability of the bulk power system.

TFCO Reliability Assessment and Performance Analysis 2020 Goals and Deliverables

- Prepare and conduct the spring and autumn NPCC System Operator Seminars.
- Develop and securely disseminate the annual compilation of "Facilities for Notification."
- Support and take part in the biennial, continent-wide Grid Security Exercise, including a review of the associated reports and Lessons Learned.
- Complete a triennial review of the individual RC Areas' restoration plans.
- 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.
- Conduct reviews of applicable NPCC Directories, Criteria, Guides and Procedures in accordance with their applicable review dates.
- Coordinate system awareness among NPCC Reliability Coordinators through periodic conference calls.
- Monitor the trends and impacts of the changing resource mix and the effects of the proliferation of the new resources on real-time operations, as well as behavior during and impacts on recovery and restoration plans.
- Provide assistance to the NERC Event Analysis Process and evaluate the operational applicability of the identified Lessons Learned.
- Review a biennial summary of operating tool failures and lessons learned for the preceding study period.
- Review and analyze the performance of Simultaneous Activation of Reserve (SAR) implementation following an event to enhance the process.

NPCC Regulatory/Governmental Affairs Advisory Group

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 reliability matters.

The Regulatory/Governmental Affairs Advisory Group activities indicated below are done in support of ERO Goal No. 3 "*Reduction of Known Risks to Reliability*" and ERO Goal No. 4 "*Identification and Assessment of Emerging Risks to Reliability*."

NPCC Regulatory/Governmental Affairs Advisory Group 2020 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, Distributed Energy Resource integration).
- 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 20% of its resources on these activities.

Resource Requirements

Personnel

- Decrease of 0.40 FTE represents reallocation of staff to situation awareness to address shift in focus areas.

Consultants and Contracts

- Increase in consultants and contracts expense is associated with increase in inherent risk and emerging risk reliability assessments.

Reliability Assessment and Performance Analysis Program

Funding sources and related expenses for the Reliability Assessment and Performance Analysis section of the 2019 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 2019 Budget & Projection, and 2020 Budget Reliability Assessment and Performance Analysis						
		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 3,332,686	$ 3,332,686	$ -	$ 3,210,055	$ (122,632)
	Penalty Sanctions	-	-	-	21,115	21,115
Total ERO Funding		**$ 3,332,686**	**$ 3,332,686**	**$ -**	**$ 3,231,169**	**$ (101,517)**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 3,332,686**	**$ 3,332,686**	**$ -**	**$ 3,231,169**	**$ (101,517)**
Expenses						
Personnel Expenses						
	Salaries	$ 1,135,264	$ 1,135,264	$ -	$ 1,006,128	$ (129,136)
	Payroll Taxes	69,027	69,027	-	64,023	(5,004)
	Benefits	219,655	219,655	-	218,787	(868)
	Retirement Costs	123,322	123,322	-	109,418	(13,904)
Total Personnel Expenses		**$ 1,547,268**	**$ 1,547,268**	**$ -**	**$ 1,398,356**	**$ (148,912)**
Meeting Expenses						
	Meetings & Conference Calls	$ 23,000	$ 23,000	$ -	$ 22,000	$ (1,000)
	Travel	216,200	216,200	-	216,200	-
Total Meeting Expenses		**$ 239,200**	**$ 239,200**	**$ -**	**$ 238,200**	**$ (1,000)**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 430,000	$ 430,000	$ -	$ 533,000	$ 103,000
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Operating Expenses		**$ 430,000**	**$ 430,000**	**$ -**	**$ 533,000**	**$ 103,000**
	Total Direct Expenses	**$ 2,216,468**	**$ 2,216,468**	**$ -**	**$ 2,169,556**	**$ (46,912)**
Indirect Expenses		**$ 1,132,814**	**$ 1,132,814**	**$ -**	**$ 1,031,701**	**$ (101,113)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 3,349,282**	**$ 3,349,282**	**$ -**	**$ 3,201,257**	**$ (148,025)**
Change in Assets		**$ (16,596)**	**$ (16,596)**	**$ -**	**$ 29,913**	**$ 46,508**
Fixed Asset Additions (C)		**$ (16,596)**	**$ (16,596)**	**$ -**	**$ 29,913**	**$ 46,508**
TOTAL BUDGET (=B+C)		**$ 3,332,686**	**$ 3,332,686**	**$ -**	**$ 3,231,169**	**$ (101,517)**
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)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	0.10	0.10	0.00
Direct Expenses	$233,297	$219,862	($13,435)
Indirect Expenses	$18,634	$19,000	$366
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	$569	$551	($18)
Total Funding Requirement	$252,500	$239,412	($13,088)

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:

- potential operational problems for the coming season are discussed,
- physical layouts and electrical characteristics of the NPCC and PJM Areas are discussed,
- application of NPCC Directory and NERC Standard requirements pertinent to operation are discussed,
- major industry issues that are important for system operators are discussed,
- significant disturbances are reviewed for lessons learned; and
- table-top drills and communication and coordination exercises are conducted.

The seminars promote camaraderie and better communication among system operators from the NPCC and PJM Reliability Coordinator (RC) Areas and the Nova Scotia Balancing Authority (BA) area. PJM RC has significant interaction with the NPCC RCs and system operators from PJM have been regular participants at past seminars. Examples of specific topics addressed at recent seminars include: 1) additions and impacts to operations of renewable resources, 2) the development of conditions and violations related to major system Blackouts, 3) human performance related to system operations, 4) cybersecurity threats and system operator concerns, 5) system restoration approaches and tie-ins to neighboring systems and 6) application of NPCC Simultaneous Activation of Reserve. Usually, control center visits are included as part of the seminar activities.

This Program also provides for:

- sharing of RC/BA existing training program and system simulator area content;
- verification and sharing of training methods;
- evaluation of training and simulator aids as they become available;
- opportunities to consolidate training among the NPCC RCs and BAs, which includes opportunities to share training material and training sessions; and
- exchange of information on internal methods of system operator training.

The training activities indicated below are done in support of ERO Goals No. 3 "*Reduction of Known Reliability Risks*" and No. 6 "*Effective and Efficient Operation*". Related contributing activities to these goals include "Working with industry forums, expand communication and encourage sharing of good industry practices for increasing Human Performance (HP) effectiveness", "Acquire, engage, develop, and retain highly qualified talent with requisite technical expertise to execute the ERO Enterprise's statutory functions" and "Strengthen coordination among NERC, Regional Entities with cross-border footprints, and North American stakeholders in support of ERO Enterprise reliability and security priorities."

Funding Drivers and Reliability Benefits

- System operators participating in the Seminars: 1) share their approaches to addressing 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 PJM 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 and participate in these seminars;
- Seminar attendees also receive Continuing Education Hours (CEHs) (normally 3 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; 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 system operator awareness and knowledge of the standards, criteria and procedures that are applied in real time operation;
- Provide more sharing of 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 and COM standards;
- NPCC will conduct two Standards and Compliance workshops in 2020, 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).

2020 Key Assumptions

In addition to the Spring and Fall Standards and Compliance workshops, NPCC regularly conducts System Operators seminars, , specifically designed with table top exercises, targeted breakout classroom sessions and presentations on current industry related activities, to provide for the most efficient exchange of information between the NPCC and Areas' training staff, 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 and Areas' training staff members. To supplement these seminars and workshops, NPCC may develop webinars that will focus on specific topics pertinent to developments related to system operations, compliance program implementation, standards development or technical issues.

The System Operator seminars involve system operators' participants from the NPCC RC/BA Areas and PJM, and are held in early May and early November.

Training, Education and Operator Certification 2020 Goals and Deliverables

- Prepare and conduct the 2020 Spring and Fall NPCC System Operator Seminars.
- Continue collaboration and sharing of the intended RC/BA approaches, experiences and materials to task identification and training development
- As needed, enhance 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 Standards PER-003-1 "*Operating Personnel Credentials"* and PER-005-2 "*Operations Personnel Training.*"
- Develop on-line operational training webinars that focus on specific topics pertinent to compliance program implementation, standards development or technical issues.
- Conduct Spring and Fall 2020 Standards and Compliance workshops addressing the development of NERC and Regional Reliability Standards and the implementation of the Compliance Monitoring and Enforcement Program (CMEP).

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

- No significant changes.

Training, Education, and Operator Certification Program

Funding sources and related expenses for the training, education, and operator certification section of the 2020 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
2019 Budget & Projection, and 2020 Budget
Training, Education, and Operator Certification

		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 184,943	$ 184,943	$ -	$ 171,524	$ (13,420)
	Penalty Sanctions	-	-	-	389	389
Total ERO Funding		**$ 184,943**	**$ 184,943**	**$ -**	**$ 171,912**	**$ (13,031)**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	67,500	67,500	-	67,500	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 252,443**	**$ 252,443**	**$ -**	**$ 239,412**	**$ (13,031)**
Expenses						
Personnel Expenses						
	Salaries	$ 18,600	$ 18,600	$ -	$ 11,793	$ (6,807)
	Payroll Taxes	1,513	1,513	-	939	(575)
	Benefits	6,805	6,805	-	5,652	(1,153)
	Retirement Costs	2,379	2,379	-	1,478	(900)
Total Personnel Expenses		**$ 29,297**	**$ 29,297**	**$ -**	**$ 19,862**	**$ (9,435)**
Meeting Expenses						
	Meetings & Conference Calls	$ 189,000	$ 189,000	$ -	$ 185,000	$ (4,000)
	Travel	15,000	15,000	-	15,000	-
Total Meeting Expenses		**$ 204,000**	**$ 204,000**	**$ -**	**$ 200,000**	**$ (4,000)**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ -	$ -	$ -	$ -	$ -
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Total Direct Expenses	**$ 233,297**	**$ 233,297**	**$ -**	**$ 219,862**	**$ (13,435)**
Indirect Expenses		**$ 19,431**	**$ 19,431**	**$ -**	**$ 19,000**	**$ (431)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 252,728**	**$ 252,728**	**$ -**	**$ 238,862**	**$ (13,866)**
Change in Assets		**$ (285)**	**$ (285)**	**$ -**	**$ 551**	**$ 836**
Fixed Asset Additions (C)		**$ (285)**	**$ (285)**	**$ -**	**$ 551**	**$ 836**
TOTAL BUDGET (=B+C)		**$ 252,443**	**$ 252,443**	**$ -**	**$ 239,412**	**$ (13,031)**
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)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	5.00	5.40	0.40
Direct Expenses	$1,409,379	$1,450,129	$40,750
Indirect Expenses	$931,695	$1,026,001	$94,306
Other Non-Operating Expenses	$0	$0	$0
Fixed Asset Additions	$28,466	$29,747	$1,281
Total Funding Requirement	$2,369,540	$2,505,877	$136,337

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 an event does occur, it is critical to provide a forum for active coordination of reliability and operation among the NPCC Reliability Coordinator areas and neighboring NERC Regions and to use an event as a learning opportunity to enhance the reliability of the interconnected bulk power system through the lessons 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 "*Reduction of Known Risks to Reliability*" and ERO Goal No. 5 – "*Identification and Reduction of Cyber and Physical Security Risks."* Related contributing activities to Goal 3 include "Analyzing system performance, events, and relationships among data sources to identify risks and mitigation strategies and provide recommendations and lessons learned, including those that are lower impact, to discover potential reliability trends early in their lifecycles" and "Promoting the use of NERC cause codes to establish a common understanding of HP triggers, collect and evaluate trends in data, and develop metrics as needed." Contributing activities to Goal 5 include "Working closely with industry, NERC's Critical Infrastructure Protection Committee (CIPC), governmental agencies, the national labs, industry forums, trade associations and other stakeholders, promote leading security practices, information sharing and analysis, and resilience."

Event Analysis Program Description

NERC, Regions and the industry analyze events, identify the lessons to be learned, and conduct a formal cause code analysis.

The Event Analysis Program recognizes that many events which occur on the bulk power system beyond those identified through NERC Reliability Standard EOP-004-4, "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 implementing a "bottom-up" approach to an event review within the framework of the NERC Event Analysis Program, consistency, comparability, flexibility, quality 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 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 is accomplished by performing 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 voluntary effort, the entity, the Region and NERC staff will collaborate to assess the NERC Brief Report or Event Analysis Report and perform a formal cause code analysis, identifying a root cause and publish any pertinent lessons learned gathered from the event.

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 a more detailed and in-depth analysis. Consistent with risk-based approach, only concise and succinct reviews are desired for more minor events. ERO EAP delineates the expectations, roles and responsibilities of the registered entities, NPCC and NERC in a uniform review of system events by the industry and promotes a 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 analysis of the lesser events on the system, learning from these events and developing recommendations, risk of larger events can be mitigated.

NPCC staff works step-by-step with the registered entity throughout the total event analysis process, permitting the entity to assume the primary role in the development of the initial event analysis, lessons learned, which may benefit the industry, along with assisting and overseeing the Standards sufficiency review and cause coding process 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.

2020 Key Assumptions

- The monitoring of Lessons Learned will continue to be a major focus of NERC and NPCC in 2020, including:
    - continued reporting, for applicable qualifying eventsin the voluntary Event Analysis Program, of more detailed information on station equipment failure, per recommendation of the AC Substation Equipment Task Force, to solicit and collect this data, to aid in future analysis of station equipment failures and to identify trends that may be a threat to the reliability of the Bulk Electric System,
    - Introduction of a new EAP categories, implemented to capture the effect of "non-consequential" loss of inverter type resources and similarly DC ties between two separate asynchronous systems,
    - continued utilization of a revised Category 1h - EMS/Loss of monitoring or control at a Control Center events Brief Report template and Addendum, developed with the input of the EMS Working Group to ensure continuation of analysis of such events to improve information collection related to such events and associated analysis, taking into account the modifications to the mandatory EOP-004-4 reporting requirements thresholds.
- NERC will post updates to the Critical Infrastructure Protection Standards to address the outstanding FERC Directives and the remaining industry concerns that were not satisfactorily responded to by the version 5 Transition Advisory Group, including:
    - The new CIP-008 reporting requirements
    - The supply chain standards, which become mandatory July 2020
    - CIP modification SDT effort on virtualization
    - Updates to CIP-002 and CIP-003
- TFIST will address cloud computing initiatives, through technical consensus comments and ballot recommendations, specifically on the topics of:
    - Cloud computing work on BES Cyber Systems Information updates to CIP-004 and CIP-011
    - Continued evaluation of coordination between CIP standards and Federal Risk and Authorization Management Program (FedRAMP) - an assessment and authorization process which U.S. federal agencies have been directed by the Office of Management and Budget to ensure security is in place when accessing cloud computing products and services
- Resource allocation to this program area will support expanded Events Analysis activities; coordination with NERC's evolving E-ISAC capabilities; and physical and cyber security outreach efforts.

Situation Awareness 2020 Goals and Deliverables

- NPCC will provide the Regional perspective and support through NPCC Event Analysis staff participation on selective NERC Technical Committees and key related NERC Subcommittees, Task Forces and Working Groups, including the Event Analysis Subcommittee, the ERO – Event Analysis/Situational Awareness Group; and utilization of The Event Analysis Management System (TEAMS).
- Work directly with applicable NPCC Task Forces and Working Groups to provide an in-depth assessment of Lessons Learned unique to the NPCC Members and NPCC Criteria.
- Promote NPCC's Event Analysis group's process for sharing and dissemination of the detailed Event Analysis Report information among industry participants (Registered Entities).
- Incorporate the Lessons Learned from participation in the GridEx V wide-area exercise.

- 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 within NPCC. Notify the Reliability Coordinators 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, 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 staff.
- Coordination and communication with the NERC Bulk Power System Awareness group in preparation for and during ongoing significant events in the NPCC's footprint and participation in the ERO Enterprise-wide Situation Awareness activities. Monitor the status of the bulk power system through the NERC Situational Awareness-FERC, NERC, Regions version 3 (SAFNRv3) tool, a near real-time operating display for the United States portion of the Reliability Coordinators footprints of North America, an enhanced visualization tool, providing more timely and accurate assessments of current conditions affecting the BPS, thus enabling NERC's and Regions' obligation to maintain situational awareness and facilitation of timely communications and collaboration with key stakeholders .

Infrastructure Security Objectives

NPCC's critical infrastructure security objectives are defined within the scope of the NPCC Task Force on Infrastructure Security & Technology, and include, but are not limited to:

- Providing a forum for NPCC review of proposed and posted documents from the NERC Critical Infrastructure Protection Committee; 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 physical and cyber security outreach efforts, will supplement infrastructure security objectives and support the ERO Enterprise contributing activity of "Working closely with industry, NERC's Critical Infrastructure Protection Committee (CIPC), governmental agencies, the national labs, industry forums, trade associations and other stakeholders, promote leading

security practices, information sharing and analysis, and resilience." NPCC's Physical Security Working Group – an NPCC group of physical security experts formed to discuss, in a secure environment, emerging threats, trends and new security technologies and strategies utilized by NPCC registered entities for the protection of their facilities in the physical arena. The Working Group is tasked with developing approaches to physical security that will enhance the reliability and resiliency of the BPS and further address any physical security issues that could challenge efficient operation of the BPS, including pertinent items identified in the biennial RISC report, under Physical and Cyber Security Vulnerabilities. The Group will function as a clearinghouse for intelligence information received from Federal, State and Local partners and will disseminate such information received to NPCC registered entities. In addition, the Working Group shall develop, review, and provide regional input on various industry physical security initiatives, working groups, and task forces, as appropriate.

NPCC's 2020 infrastructure security goals and objectives, support ERO Goal No. 5 – "*Identification and Reduction of Cyber and Physical Risks*." 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 "Leverage engagement with registered entities to encourage effective security practices and controls."

Infrastructure Security 2020 Goals and Deliverables

- Monitor the reliable implementation of the Cyber Security Standards.
- Monitor the Homeland Security Information Network, E- ISAC, NERC Alerts and Canadian Information Sharing and share information with the NPCC CO-8 Working Group, NPCC PSWG and NPCC members' cyber security experts.
- 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 review of cross border emergency telecommunications to verify each Area can communicate with each other.
- Provide support and technical input for Task Force related Bulk Electric System risks as identified by the NERC Reliability Issues Steering Committee. TFIST and PSWG will conduct a thorough review, provide comments as necessary and act on posted materials as directed and applicable.
- Support the NERC CIPC Grid Exercise Working Group in GridEx VI planning and simulation.
- 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.

- 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 2020 Goals and Deliverables

NPCC's system operations security objectives are defined within the scope of the NPCC Task Force on Coordination of Operation and include, but are not limited 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 ensuring cyber security concerns are addressed.

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 15% of its resources on this activity.

Resource Requirements

Personnel

- Increase of 0.40 FTE represents reallocation of staff to address shift in focus areas.

Situation Awareness and Infrastructure Security Program

Funding sources and related expenses for the situation awareness and infrastructure security section of the 2020 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
2019 Budget & Projection, and 2020 Budget
Situation Awareness and Infrastructure Security

		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 2,366,685	$ 2,366,685	$ -	$ 2,484,879	$ 118,195
	Penalty Sanctions	-	-	-	20,998	20,998
Total ERO Funding		**$ 2,366,685**	**$ 2,366,685**	**$ -**	**$ 2,505,877**	**$ 139,193**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 2,366,685**	**$ 2,366,685**	**$ -**	**$ 2,505,877**	**$ 139,193**
Expenses						
Personnel Expenses						
	Salaries	$ 832,408	$ 832,408	$ -	$ 924,110	$ 91,702
	Payroll Taxes	57,432	57,432	-	61,713	4,281
	Benefits	201,196	201,196	-	202,020	824
	Retirement Costs	89,043	89,043	-	99,986	10,943
Total Personnel Expenses		**$ 1,180,079**	**$ 1,180,079**	**$ -**	**$ 1,287,829**	**$ 107,750**
Meeting Expenses						
	Meetings & Conference Calls	$ 10,000	$ 10,000	$ -	$ 8,000	$ (2,000)
	Travel	89,300	89,300	-	94,300	5,000
Total Meeting Expenses		**$ 99,300**	**$ 99,300**	**$ -**	**$ 102,300**	**$ 3,000**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 130,000	$ 130,000	$ -	$ 60,000	$ (70,000)
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Operating Expenses		**$ 130,000**	**$ 130,000**	**$ -**	**$ 60,000**	**$ (70,000)**
	Total Direct Expenses	**$ 1,409,379**	**$ 1,409,379**	**$ -**	**$ 1,450,129**	**$ 40,750**
Indirect Expenses		**$ 971,538**	**$ 971,538**	**$ -**	**$ 1,026,001**	**$ 54,463**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 2,380,918**	**$ 2,380,918**	**$ -**	**$ 2,476,130**	**$ 95,212**
Change in Assets		**$ (14,233)**	**$ (14,233)**	**$ -**	**$ 29,747**	**$ 43,980**
Total Funding (A) Requirement		**$ 2,395,151**	**$ 2,395,151**	**$ -**	**$ 2,446,383**	**$ 51,232**
Fixed Asset Additions						
	Computer & Software CapEx	-	-	-	-	-
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	(14,233)	(14,233)	-	29,747	43,980
Fixed Asset Additions (C)		**(14,233)**	**(14,233)**	**-**	**29,747**	**43,980**
TOTAL BUDGET (=B+C)		2,366,685	2,366,685	-	2,505,877	139,193
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (0)**	**$ (0)**	**$ -**	**$ 0**	**$ 0**

Administrative Services

Administrative Services Program Resources (in whole dollars)	Direct Expenses			FTEs		
	2019 Budget	2020 Budget	Increase (Decrease)	2019 Budget	2020 Budget	Increase (Decrease)
Technical Committees and Members Forum	$74,483	$75,793	$1,310	0.50	0.50	0.00
General and Administrative [2]	$3,391,903	$3,874,453	$482,550	2.50	2.73	0.23
Legal and Regulatory	$612,934	$761,007	$148,073	1.00	2.00	1.00
Information Technology	$1,083,781	$1,314,119	$230,339	2.00	2.00	0.00
Human Resources	$156,946	$158,731	$1,785	1.00	1.00	0.00
Finance and Accounting	$642,798	$703,291	$60,493	2.00	2.00	0.00
Total Administrative Services[1]	$5,962,845	$6,887,395	$924,550	9.00	10.23	1.23

[1] NPCC's 2020 Administrative Services Direct Expenses and Fixed Assets total $6,887,395, of which $409,450 is allocated to NPCC's Criteria Services division, which is a non-statutory function. As a result of the allocation to the Criteria Services division, the Administrative Expenditures included in the 2020 statutory budget are $6,477,945 which is an increase of $743,865 from the 2019 budget of $5,734,080.

[2] Succession implementation costs of $444,540 included in General and Administrative Direct Expenses will be funded from Board approved Business Continuity Reserves and will not impact assessments.

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 2020 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
2019 Budget & Projection, and 2020 Budget
ADMINISTRATIVE SERVICES

		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ (100,108)	$ (100,108)	$ -	$ (593,855)	$ (493,746)
	Penalty Sanctions	-	-	-	-	-
Total ERO Funding		**$ (100,108)**	**$ (100,108)**	**$ -**	**$ (593,855)**	**$ (493,746)**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	55,800	55,800
Total Funding (A)		**$ (100,108)**	**$ (100,108)**	**$ -**	**$ (538,055)**	**$ (437,946)**
Expenses						
Personnel Expenses						
	Salaries	$ 2,147,254	$ 2,126,254	$ (21,000)	$ 2,433,049	$ 285,794
	Payroll Taxes	107,437	105,437	(2,000)	126,595	19,158
	Benefits	493,115	478,115	(15,000)	674,649	181,534
	Retirement Costs	296,142	294,142	(2,000)	313,571	17,429
Total Personnel Expenses		**$ 3,043,948**	**$ 3,003,948**	**$ (40,000)**	**$ 3,547,864**	**$ 503,916**
Meeting Expenses						
	Meetings & Conference Calls	$ 162,750	$ 162,750	$ -	$ 162,750	$ -
	Travel	135,100	135,100	-	129,100	(6,000)
Total Meeting Expenses		**$ 297,850**	**$ 297,850**	**$ -**	**$ 291,850**	**$ (6,000)**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 95,000	$ 95,000	$ -	$ 361,000	$ 266,000
	Office Rent	820,700	820,700	-	832,700	12,000
	Office Costs	676,347	676,347	-	685,981	9,634
	Professional Services	978,000	978,000	-	947,000	(31,000)
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	51,000	51,000	-	51,000	-
Total Operating Expenses		**$ 2,621,047**	**$ 2,621,047**	**$ -**	**$ 2,877,681**	**$ 256,634**
	Total Direct Expenses	**$ 5,962,845**	**$ 5,922,845**	**$ (40,000)**	**$ 6,717,395**	**$ 754,550**
Indirect Expenses		**$ (6,217,845)**	**$ (6,217,845)**	**$ -**	**$ (6,272,855)**	**$ (55,010)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ (255,000)**	**$ (295,000)**	**$ (40,000)**	**$ 444,540**	**$ 699,540**
Change in Assets		**$ 154,892**	**$ 194,892**	**$ 40,000**	**$ (982,595)**	**$ (1,137,486)**
Fixed Asset Additions (C)		**$ 255,000**	**$ 255,000**	**$ -**	**$ -**	**$ (255,000)**
TOTAL BUDGET (=B+C)		**$ -**	**$ (40,000)**	**$ (40,000)**	**$ 444,540**	**$ 444,540**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (100,108)**	**$ (60,108)**	**$ 40,000**	**$ (982,595)**	**$ (882,486)**

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.

2020 Key Assumptions

- NPCC's standing committee and subgroup structure for effective stakeholder involvement will continue in 2020.
- 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 2020.
- 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 2020 Goals and Deliverables

- The 2020 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 2020 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

- No significant changes.

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

- During 2020 an executive search will be conducted in order to identify a successor CEO to transition into that role by vote of the Membership at its Annual Meeting to become effective January 1, 2021. The incumbent President and CEO has identified a planned retirement during the first quarter of 2021. The expectation is that the identified successor will join NPCC by early November or December, 2020 in an executive leadership capacity. Costs related to the executive search efforts and succession plan implementation will be funded from the existing Business Continuity Reserve, identified by the NPCC Board of Directors in 2017 and approved at varying intervals within 2020 by the Board for reserve release. Therefore, 2020 assessments will not be impacted by these succession-related expenses.

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, consistent with ERO Goal 6. In support of ERO Goal 4., 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 plans to hire one FTE in the Legal and Regulatory program in 2020. A paralegal/legal assistant will support General Counsel and add to the overall efficiency of the organization. This addition is partially offset by a projected decrease in professional fees.

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 2020 Business Plan and Budget assumes agreed-upon ERO Enterprise applications will be available and includes only NPCC costs for Region specific support needs.

2020 Key Assumptions

- Continue to maintain the compliance portal through collaboration with other Regional Entities and NERC (CUG), while transitioning to the ERO Enterprise CMEP IT Tool (Align).
- 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.

2020 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:

- Continue to expand the utilization of the document management system throughout the company.
- Constantly review and evaluate security measures taken to reduce breach of security risks.

- Ensure all information systems are functional and secure, and that all applications running on those systems meet business requirements for performance, availability, and security.
- 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.
- Upgrade various hardware and equipment.

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2020.

Fixed Assets

- Capital expenditures planned for 2020 include the continuing implementation and enhancement of the document management system and equipment upgrades.

Human Resources

Program Scope and Functional Description

NPCC has assembled an exceptional team of highly qualified employees to carry out its activities. 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

- No significant changes.

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.

2020 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

- No significant changes.

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 2017 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 2017 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 ISOs/BAAs within NPCC as the designees for the load serving entities (LSEs) 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 ISOs/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 net energy for load (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 _% 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 _% 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 _% 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 BAA's total average percentage of enforcement activities. The portion allocated to the U.S. BAA's 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.

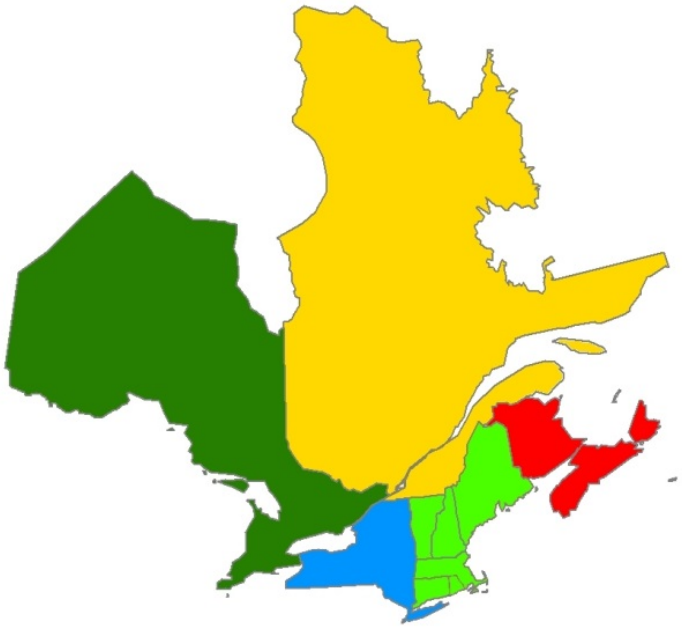
Any penalty monies received from NPCC registered entities within the U.S. by June 30th of the year preceding the business plan and budget year are then allocated among the NPCC program areas based on their FTE ratio and between the U.S. BAAs based on their relative NELs, and then added to the total compliance 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 Québec 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
2020 Business Plan and Budget



Section B – Supplemental Financial Information

Reserve Balance

Table B-1 Reserve Balance

Working Capital and Operating Reserve Analysis 2019-2020
REGIONAL ENTITY DIVISION

	Total Reserve	Operating Reserve	Working Capital	Business Continuity
Beginning Total Reserve, December 31, 2018	4,969,944	2,713,006	1,316,938	940,000
Plus: 2019 ERO Funding (from LSEs or designees)	15,003,411	15,003,411		
Plus: 2019 Other funding sources	67,500	67,500		
Less: 2019 Projected expenses & capital expenditures	(15,618,891)	(15,618,891)		
Projected Total Reserve, December 31, 2019	**4,421,964**	**2,165,026**	**1,316,938**	**940,000**
Desired Total Reserve, December 31, 2020	**3,402,353**	1,523,478 [1]	1,383,415 [2]	495,460 [3]
Less: Projected Total Reserve, December 31, 2019	(4,421,964)	(2,165,026)	(1,316,938)	(940,000)
Increase(decrease) in assessments to achieve desired Total Reserve	**(1,019,611)**	(641,548)	66,477	(444,540)

2020 Expenses and Capital Expenditures	16,601,647
Less: Penalty Sanctions [4]	(120,000)
Less: Other Funding Sources	(123,300)
Less: Release of Business Continuity Reserve Funds [3]	(444,540)
Adjustment to Working Capital to achieve desired Total Reserve balance [2]	66,477
Adjustment to Operating Reserve to achieve desired Total Reserve balance [1]	(641,548)
2020 Assessment	**15,338,737**

[1] Operating Reserve within a range from 8.33% to 25.00% of Budget. $1,523,478 represents 9.18% of the 2020 budget of $16,601,647
[2] Working Capital equal to 8.33% of Budget. $1,383,415 represents 8.33% of the 2020 budget of $16,601,647
[3] Business Continuity Reserve (BCR) established in 2017 as approved by the NPCC Board of Directors to fund Succession Planning related expenses.
[4] Represents collections July 1, 2018 to June 30, 2019.

Explanation of Changes in Reserve Policy from Prior Year

There was no change to the existing Working Capital and Operating Reserve Policy. A separate Business Continuity Reserve (BCR) in the amount of $1,000,000 (allocated between the Regional Entity and Criteria Services divisions) was established in 2017 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 drawn upon as subsequently brought before the Board of Directors for approval of release of funds in association with President & CEO succession related activities associated with the planned or a sudden retirement, as well as other sudden changing workforce staffing requirements which could be brought about by coincident multiple staff retirements.

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 2020 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, 2019 are to be used to offset assessments in the 2020 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, 2018 through June 30, 2019 are listed below. Penalty monies received from July 1, 2019 through June 30, 2020 will be used to offset U.S. load serving entity designee assessments in the 2021 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, 2019	Date Received	Amount Received
	7/16/2018	$ 120,000.00
Total Penalties Received		**$ 120,000.00**

Table B-3 Supplemental Funding

Outside Funding Breakdown By Program (excluding ERO Assessments & Penalty Sanctions)	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget
Reliability Standards				
Total	$ -	$ -	$ -	$ -
Compliance Monitoring, Enforcement & Org. Registration				
	$ -	$ -	$ -	$ -
	-	-	-	-
Total	$ -	$ -	$ -	$ -
Reliability Assessment and Performance Analysis				
	$ -	$ -	$ -	$ -
	-	-	-	-
Total	$ -	$ -	$ -	$ -
Training and Education				
Workshops	$ 67,500	$ 67,500	$ 67,500	$ -
Total	$ 64,000	$ 67,500	$ 67,500	$ -
Situation Awareness and Infrastructure Security				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Technical Committees and Member Forums				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Administrative Services Programs				
Interest & Investment Income	$ -	$ -	$ 55,800	$ 55,800
Total	$ -	$ -	$ 55,800	$ 55,800
Total Outside Funding	$ 64,000	$ 67,500	$ 123,300	$ 55,800

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- NPCC estimates interest & investment income of $55,800 in 2020 from investment of reserves in a 100% U.S. Treasury money market fund, which will offset 2020 assessments.

Table B-4 Personnel Expenses

Personnel Expenses	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Salaries					
Salary	$ 7,298,280	$ 7,298,280	$ 7,664,262	$ 365,982	5.0%
Employment Agency Fees	$ 10,000	$ 10,000	$ 16,000	$ 6,000	60.0%
Temporary Office Services	$ 24,000	$ 24,000	$ 24,000	$ -	0.0%
Total Salaries	$ 7,332,280	$ 7,332,280	$ 7,704,262	$ 371,982	5.1%
Total Payroll Taxes	$ 449,994	$ 449,994	$ 479,019	$ 29,026	6.5%
Benefits					
Education Reimbursement	$ 32,000	$ 32,000	$ 27,500	$ (4,500)	-14.1%
Training and Seminars	$ 58,290	$ 58,290	$ 83,580	$ 25,290	43.4%
Medical Insurance	$ 901,783	$ 901,783	$ 1,168,854	$ 267,071	29.6%
Life-LTD-STD Insurance	$ 94,804	$ 94,804	$ 110,889	$ 16,085	17.0%
Worker's Compensation	$ 20,000	$ 20,000	$ 32,000	$ 12,000	60.0%
Vacation	$ 506,201	$ 506,201	$ 504,062	$ (2,139)	-0.4%
Relocation	$ -	$ -	$ -	$ -	-
Total Benefits	$ 1,613,078	$ 1,613,078	$ 1,926,885	$ 313,806	19.5%
Retirement					
Pension Contribution	$ -	$ -	$ -	$ -	-
Employee Savings Plan	$ 741,511	$ 741,511	$ 770,950	$ 29,440	4.0%
Savings Admin	$ 36,000	$ 36,000	$ 36,000	$ -	0.0%
Deferred Compensation	$ 76,000	$ 76,000	$ 76,000	$ -	0.0%
Total Retirement	$ 853,511	$ 853,511	$ 882,950	$ 29,440	3.4%
Total Personnel Costs	**$ 10,248,862**	**$ 10,248,862**	**$ 10,993,117**	**$ 744,254**	**7.3%**
FTEs	38.86	38.86	41.09	2.23	5.7%
Cost per FTE					
Salaries	$ 188,685	$ 188,685	$ 187,497	$ (1,187)	-0.6%
Payroll Taxes	$ 11,580	$ 11,580	$ 11,658	$ 78	0.7%
Benefits	$ 41,510	$ 41,510	$ 46,894	$ 5,384	13.0%
Retirement	$ 21,964	$ 21,964	$ 21,488	$ (476)	-2.2%
Total Cost per FTE	**$ 263,738**	**$ 263,738**	**$ 267,538**	**$ 3,799**	**1.4%**

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- Increase in Training and Seminars is due to an increase per employee training budget.
- Medical insurance increase reflects a premium increase of 8%. Additionally, less employees are waiving NPCC coverage for that of a prior employer.
- Personnel expenses include some succession planning related costs that will be funded through business continuity reserves and do not impact assessments.

Table B-5 Meeting Expense

Meeting Expenses	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Meetings	$ 370,750	$ 370,750	$ 361,750	$ (9,000)	-2.4%
Travel	$ 845,900	$ 845,900	$ 845,900	$ -	0.0%
Conference Calls	$ 36,000	$ 36,000	$ 36,000	$ -	0.0%
Total Meeting Expenses	**$ 1,252,650**	**$ 1,252,650**	**$ 1,243,650**	**$ (9,000)**	**-0.7%**

Explanation of Significant Variances – 2020 Budget versus 2019 Budget

- None.

Table B-6 Consultants and Contracts

Consultants	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Consultants					
Reliability Standards	$ -	$ -	$ -	$ -	-
Compliance Enforcement and Organization Registration and Certification	$ -	$ -	$ -	$ -	-
Reliability Assessment and Performance Analysis	$ -	$ -	$ -	$ -	-
Training and Education	$ -	$ -	$ -	$ -	-
Situation Awareness and Infrastructure Security	$ -	$ -	$ -	$ -	-
Member Forums	$ -	$ -	$ -	$ -	-
General and Administrative	$ -	$ -	$ 279,000	$ 279,000	-
Legal and Regulatory	$ -	$ -	$ -	$ -	-
Information Technology	$ -	$ -	$ -	$ -	-
Human Resources	$ -	$ -	$ -	$ -	-
Accounting and Finance	$ -	$ -	$ -	$ -	-
Consultants Total	**$ -**	**$ -**	**$ 279,000**	**$ 279,000**	**-**

Contracts	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Reliability Standards	$ 10,000	$ 10,000	$ 20,000	$ 10,000	100.0%
Compliance Enforcement and Organization Registration and Certification	$ 1,357,150	$ 1,357,150	$ 1,097,150	$ (260,000)	-19.2%
Reliability Assessment and Performance Analysis	$ 430,000	$ 430,000	$ 533,000	$ 103,000	24.0%
Training and Education	$ -	$ -	$ -	$ -	-
Situation Awareness and Infrastructure Security	$ 130,000	$ 130,000	$ 60,000	$ (70,000)	-53.8%
Member Forums	$ -	$ -	$ -	$ -	-
General and Administrative	$ 88,000	$ 88,000	$ 75,000	$ (13,000)	-14.8%
Legal and Regulatory	$ -	$ -	$ -	$ -	-
Information Technology	$ -	$ -	$ -	$ -	-
Human Resources	$ -	$ -	$ -	$ -	-
Accounting and Finance	$ 7,000	$ 7,000	$ 7,000	$ -	0.0%
Contracts Total	**$ 2,022,150**	**$ 2,022,150**	**$ 1,792,150**	**$ (230,000)**	**-11.4%**
Total Consultants and Contracts	**$ 2,022,150**	**$ 2,022,150**	**$ 2,071,150**	**$ 49,000**	**2.4%**

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- During 2020 an executive search will be conducted in order to identify a successor CEO. Consulting costs related to the search efforts will be funded from the existing Business Continuity Reserves. 2020 assessments will not be impacted by these succession-related expenses.
- 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 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Office Rent	$ 650,000	$ 650,000	$ 650,000	$ -	0.0%
Utilities	$ 45,000	$ 45,000	$ 47,000	$ 2,000	4.4%
Maintenance	$ 37,000	$ 37,000	$ 37,000	$ -	0.0%
Security	$ 2,700	$ 2,700	$ 2,700	$ -	0.0%
Real Estate Taxes	$ 86,000	$ 86,000	$ 96,000	$ 10,000	11.6%
Total Office Rent	**$ 820,700**	**$ 820,700**	**$ 832,700**	**$ 12,000**	**1.5%**

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- None.

Table B-8 Office Costs

Office Costs	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Telephone	$ 88,720	$ 88,720	$ 88,720	$ -	0.0%
Internet Expense	$ 82,740	$ 82,740	$ 74,340	$ (8,400)	-10.2%
Office Supplies	$ 33,000	$ 33,000	$ 33,000	$ -	0.0%
Computer Supplies and Maintenance	$ 397,387	$ 397,387	$ 424,921	$ 27,534	6.9%
Subscriptions & Publications	$ 13,500	$ 13,500	$ 14,000	$ 500	3.7%
Dues	$ 3,400	$ 3,400	$ 3,400	$ -	0.0%
Postage	$ 1,200	$ 1,200	$ 1,200	$ -	0.0%
Express Shipping	$ 10,000	$ 10,000	$ 6,000	$ (4,000)	-40.0%
Copying	$ 26,400	$ 26,400	$ 26,400	$ -	0.0%
Reports	$ 8,000	$ 8,000	$ 2,000	$ (6,000)	-75.0%
Stationary and Office Forms	$ 2,000	$ 2,000	$ 2,000	$ -	0.0%
Equipment Repair/Service Contracts	$ -	$ -	$ -	$ -	-
Bank Charges	$ 10,000	$ 10,000	$ 10,000	$ -	0.0%
Sales and Use Tax	$ -	$ -	$ -	$ -	-
Merchant Credit Card Fees	$ -	$ -	$ -	$ -	-
Presentation and Publicity	$ -	$ -	$ -	$ -	-
Total Office Costs	**$ 676,347**	**$ 676,347**	**$ 685,981**	**$ 9,634**	**1.4%**

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- Total Office costs are expected to remain relatively flat.

Table B-9 Professional Services

Professional Services	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
BOT Fee	$ 346,000	$ 346,000	$ 332,000	$ (14,000)	-4.0%
BOT Search Fee	$ -	$ -	$ -	$ -	-
Legal - Reorganization	$ -	$ -	$ -	$ -	-
Accounting & Auditing Fees	$ 300,000	$ 300,000	$ 310,000	$ 10,000	3.3%
Legal Fees - Other	$ 262,000	$ 262,000	$ 235,000	$ (27,000)	-10.3%
Insurance - Commercial	$ 70,000	$ 70,000	$ 70,000	$ -	0.0%
Total Services	**$ 978,000**	**$ 978,000**	**$ 947,000**	**$ (31,000)**	**-3.2%**

Table B-10 Miscellaneous

Miscellaneous Expense	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Miscellaneous Expense	$ 51,000	$ 51,000	$ 51,000	$ -	0.0%
Total Miscellaneous Expense	**$ 51,000**	**$ 51,000**	**$ 51,000**	**$ -**	**0.0%**

Table B-11 Other Non-Operating Expenses

Other Non-Operating Expenses	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Interest Expense	$ -	$ -	$ -	$ -	-
Office Relocation	$ -	$ -	$ -	$ -	-
Total Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**-**

Table B-12 Fixed Assets

Fixed Asset Additions	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Equipment CapEx	$ -	$ -	$ -	$ -	-
Computer & Software CapEx	$ 170,000	$ 170,000	$ 170,000	$ -	0.0%
Furniture & Fixtures CapEx	$ -	$ -	$ -	$ -	-
Leasehold Improvements	$ -	$ -	$ -	$ -	-
Allocation of Fixed Assets	$ -	$ -	$ -	$ -	-
Total Fixed Asset Additions	**$ 170,000**	**$ 170,000**	**$ 170,000**	**$ -**	**0.0%**

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- Capital expenditures planned for 2020 include the continuing implementation of the document management system and equipment upgrades.

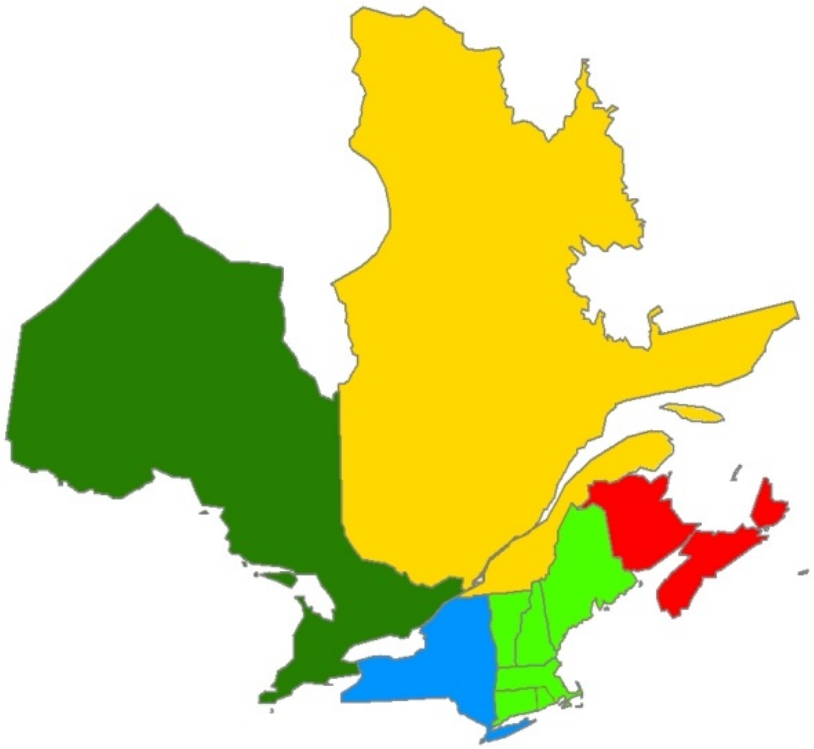
Table B-13 2020 and 2021 Projections

Table to be Inserted

Assumptions

Section C — Criteria Services Division Activities

2020 Business Plan and Budget



Section C – Criteria Services Division Activities

Criteria Services Division (in whole dollars)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	2.14	2.16	0.02
Total Direct Expenses	$662,756	$709,217	$46,462
Total Indirect Expenses	$398,765	$409,450	$10,685
Other Non-Operating Expenses	$0	$0	$0
Working Capital and Operating Reserves Requirement	($32,655)	($79,265)	($46,611)
Fixed Asset Additions	$30,000	$30,000	$0
Funding Requirement	$1,058,866	$1,069,402	$10,536

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 new or revised Regionally-specific, more stringent reliability criteria and supporting guideline or procedural documents. The requirements in NPCC Reliability Criteria apply only to those facilities defined as NPCC Bulk Power System elements through the performance based methodology identified in the NPCC Document A-10, "Classification of Bulk Power System Elements."

In accordance with the NERC Rules of Procedure (RoP) Section 313, Regional Entities may develop Regional Criteria necessary to implement, augment, or facilitate compliance with NERC Reliability Standards. These Regional Criteria may also be utilized to address issues not within the scope or jurisdiction of FERC as outlined in Section 215 of the Federal Power Act, such as resource adequacy. Regional Criteria may also address Canadian Provincial reliability issues, and may include specific operating or planning parameters, guides, agreements, protocols or other documents used to enhance the reliability of the Bulk Power System in the Region. These documents typically provide benefits by promoting more consistent implementation of the NERC Reliability Standards within the Region. These documents are not NERC Reliability Standards, Regional Reliability Standards, or Regional Variances, and therefore are not enforceable under the authority delegated by NERC pursuant to delegation agreements.

As NERC Reliability Standards are revised or new standards are developed, NPCC performs reviews of any associated Regional Criteria for possible impact.

For 2020 and beyond, the potential reliability impacts of increased penetration of Distributed Energy Resources (DER, e.g. solar and wind), and changing fuel mixes warrant further consideration. The Criteria Services Division has a unique opportunity to review these issues and develop criteria, guideline, and procedural documents for DER which may be outside of the jurisdiction of FERC and NERC Reliability Standards. Participation of the entities responsible for development of DER renewable resources to develop reliability documents will become increasingly important over time. Outreach, collaboration, and coordination of topics related to DER will enable NPCC to develop guidelines allowing more effective integration of these resources.

Increasing resilience of the BPS through alternative approaches to standards development using potential NPCC criteria, guidelines, and whitepapers will also be continually reviewed by NPCC's body of subject matter experts.

Membership and Governance

Full members, in accordance with NPCC's Amended and Restated Bylaws, are subject to compliance with Regionally-specific criteria 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.

Under Criteria Services NPCC will identify for membership, those entities involved in emerging technologies to assure that those entities that have an impact on Bulk Electric System reliability are included in appropriate NPCC activities.

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 2020 Assumptions and Cost Impacts

The Criteria Services division activities are expected to remain stable or slightly increase throughout 2020 depending on reliability need.

- 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.

2020 Primary Goals and Objectives

- Continue with the development and maintenance of a set of NPCC Directories which augment or add specificity to 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 NPCC 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.
    - Directory No. 12 "Automatic Underfrequency Load Shedding Requirements" will be retired in 2020 upon approval of PRC-006-NPCC-2 "Automatic Underfrequency Load Shedding" Regional Standard
- Identify opportunities to develop criteria, procedures or guideline documents to address reliability related matters with DER.
- Identify opportunities to address improvements in BES resilience with NPCC processes and documentation.
- Continually review the need to 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 augment and are not 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.
    -
    - 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 augment, add specificity, or address issues not covered in the NERC Reliability Standards as mandated by the NERC Rules of Procedure. The conversion of NPCC's reliability 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 requirements

and "standards 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 2020, 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 continue to be applied to the existing Directories to make them more consistent with the format of NERC standards. As NERC standards improve, the need for NPCC Directories and the amount of criteria contained therein may decrease over time, however in the interim, significant review is necessary to ensure the criteria remain consistent 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.

Additionally, as NERC Reliablity Standards are developed, associated Directories will be reviewed for continued need. This review will identify the incremental reliability enhancement the Directory's criteria will yield, determine if the enhancement is sufficient to warrant retention and if so, are there any potential cost effective alternatives that may exist to achieve that enhanced level of reliablity.

NPCC Operations and Planning Directories

The following Directories are envisioned to remain active for 2020.

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, 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 2019.

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 lead the review and revision of this Directory in 2018. The Directory was re-formatted to be consistent with the style of NERC standards.

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.

NPCC Criteria Compliance and Enforcement Program (CCEP)

The NPCC Criteria Services division supports the reliable operation of the NPCC Bulk Power System (BPS) through implementation of the NPCC Criteria Compliance Program (CCEP). This program monitors, assesses, and enforces compliance on a subset of the regionally specific, more stringent NPCC Criteria that are unique to the NPCC BPS and are not duplicative of the NERC Reliability Standards. The physical characteristics and topology of the transmission system within the Region require that certain aspects of criteria be monitored for compliance.

The Criteria Services division and the NPCC Compliance Committee (CC) administer the CCEP. The CC is a stakeholder body consisting of NPCC Members and is structured by the seven sectors that appear in the NPCC Bylaws.

Noncompliance to NPCC Criteria is not subject to monetary sanctions and results in a notification of noncompliance to the Chief Executive Officer of the appropriate Full Member.

The CCEP program is described in document CCEP-1, *NPCC Criteria Compliance and Enforcement Program (CCEP) Process Document.* The CC reviews CCEP-1 annually and revisions to CCEP-1 are reviewed and approved by the CC.

The CCEP-1 document:

1. Provides a comprehensive CCEP Process Flow Diagram showing the process of evaluating and approving Criteria Certification submittals, and additional processes and responsibilities in the event that noncompliances, disputes, and sanctions arise;
2. Describes the roles and responsibilities of Reporting Members, the CC, the NPCC Reliability Coordinating Committee, and the Enforcement Panel in the compliance review and enforcement process
3. Describes non-monetary Sanctions, the Lateness Policy, and the Arbitration/Dispute Resolution process
4. Addresses the development of Mitigation Plans for any violations under the enforcement process

The CCEP Working Group (under the CC) develops a draft of the annual CCEP Implementation Plan and updates the blank certification templates for the upcoming Plan year. The Implementation Plan identifies the subset of Criteria that must be certified to and includes the certification form due dates. The draft CCEP Implementation Plan for the coming year and the draft certification templates are then submitted to the CC for review and approval.

The CC members review the completed certification forms that are returned by Full Members. NPCC Staff develops an assessment report and scorecard that summarizes the certifications that were received for the CC to review and approve. The assessment report and any recommendations on noncompliances are then presented to the NPCC Reliability Coordinating Committee (RCC) for approval.

Compliance to the NPCC Criteria is a responsibility of the NPCC Members and is codified in the *AMENDED AND RESTATED BYLAWS OF NORTHEAST POWER COORDINATING COUNCIL, INC.* Implementation of the CCEP is also consist with the current Memorandum of Understating that NPCC has with its Canadian Members.

Explanation of Significant Variances – 2020 Budget versus 2019 Budget

- None.

2019 Budget and Projection and 2020 Budget Comparisons

Statement of Activities and Capital Expenditures
2019 Budget & Projection, and 2020 Budget

CRITERIA SERVICES DIVISION

		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ -	$ -	$ -	$ -	$ -
	Penalty Sanctions	-	-	-	-	-
Total ERO Funding		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Membership Dues	1,058,866	1,058,866	-	1,069,402	10,536
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 1,058,866**	**$ 1,058,866**	**$ -**	**$ 1,069,402**	**$ 10,536**
Expenses						
Personnel Expenses						
	Salaries	$ 371,938	$ 371,938	$ -	$ 367,979	$ (3,959)
	Payroll Taxes	23,696	23,696	-	24,864	1,168
	Benefits	102,779	102,779	-	123,261	20,482
	Retirement Costs	43,182	43,182	-	41,954	(1,228)
Total Personnel Expenses		**$ 541,596**	**$ 541,596**	**$ -**	**$ 558,057**	**$ 16,462**
Meeting Expenses						
	Meetings	$ 5,000	$ 5,000	$ -	$ 14,000	$ 9,000
	Travel	56,800	56,800	-	56,800	-
Total Meeting Expenses		**$ 61,800**	**$ 61,800**	**$ -**	**$ 70,800**	**$ 9,000**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 55,360	$ 55,360	$ -	$ 76,360	$ 21,000
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	4,000	4,000	-	4,000	-
Total Operating Expenses		**$ 59,360**	**$ 59,360**	**$ -**	**$ 80,360**	**$ 21,000**
	Total Direct Expenses	**$ 662,756**	**$ 662,756**	**$ -**	**$ 709,217**	**$ 46,462**
Indirect Expenses		**$ 415,818**	**$ 415,818**	**$ -**	**$ 409,450**	**$ (6,368)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 1,078,574**	**$ 1,078,574**	**$ -**	**$ 1,118,668**	**$ 40,094**
Change in Assets		**$ (19,707)**	**$ (19,707)**	**$ -**	**$ (49,265)**	**$ (29,558)**
Fixed Asset Additions (C)		**$ 30,000**	**$ 30,000**	**$ -**	**$ 30,000**	**$ -**
TOTAL BUDGET (=B+C)		**$ 1,108,574**	**$ 1,108,574**	**$ -**	**$ 1,148,668**	**$ 40,094**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (49,707)**	**$ (49,707)**	**$ -**	**$ (79,265)**	**$ (29,558)**

Personnel Analysis

Total FTE's by Program Area	Budget 2019	Projection 2019	Direct FTEs 2020 Budget	Shared FTEs[1] 2020 Budget	Total FTEs 2020 Budget	Change from 2019 Budget
CRITERIA SERVICES DIVISION						
Operational Programs						
Reliability Standards	1.07	1.07	1.00	0.08	1.08	0.01
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	0.08	1.08	0.01
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**	**0.16**	**2.16**	**0.02**
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**	**0.16**	**2.16**	**0.02**

[1]A shared FTE is defined as an employee who performs both Regional Entity and Criteria Services division functions.

Reserve Analysis 2019 - 2020

Working Capital and Operating Reserve Analysis 2019-2020
CRITERIA SERVICES DIVISION

	Total Reserve	Operating Reserve	Working Capital	Business Continuity
Beginning Total Reserve, December 31, 2018	571,369	422,614	88,755	60,000
2019 Non-Statutory Funding (from members)	1,058,866	1,058,866		
Plus: 2019 Other funding sources	0	0		
Less: 2019 Projected expenses & fixed asset additions	(1,108,574)	(1,108,574)		
Projected Total Reserve, December 31, 2019	**521,661**	**372,906**	**88,755**	**60,000**
Desired Total Reserve, December 31, 2020	**442,396**	320,137 [1]	95,718 [2]	26,540 [3]
Less: Projected Total Reserve, December 31, 2019	(521,661)	(372,906)	(88,755)	(60,000)
Increase(decrease) in assessments to achieve desired Total Reserve	(79,265)	(52,769)	6,963	(33,460)

2020 Funding requirement for expenses and fixed asset additions	1,148,668
Less: Other Funding Sources	(4,200)
Less: Release of Business Continuity Reserve Funds [3]	(33,460)
Adjustment to Working Capital to achieve desired Total Reserve balance [2]	6,963
Adjustment to Operating Reserve to achieve desired Total Reserve balance [1]	(52,769)
2020 Funding and reserve requirement	1,065,202

[1] Total NPCC Operating Reserve must be within a range from 8.33% to 25.00% of Budget. $320,137 represents 27.87% of the 2019 CS budget of $1,148,668.

[2] Total NPCC Working Capital must equal 8.33% of Budget. $95,718 represents 8.33% of the 2019 CS budget of $1,148,668.

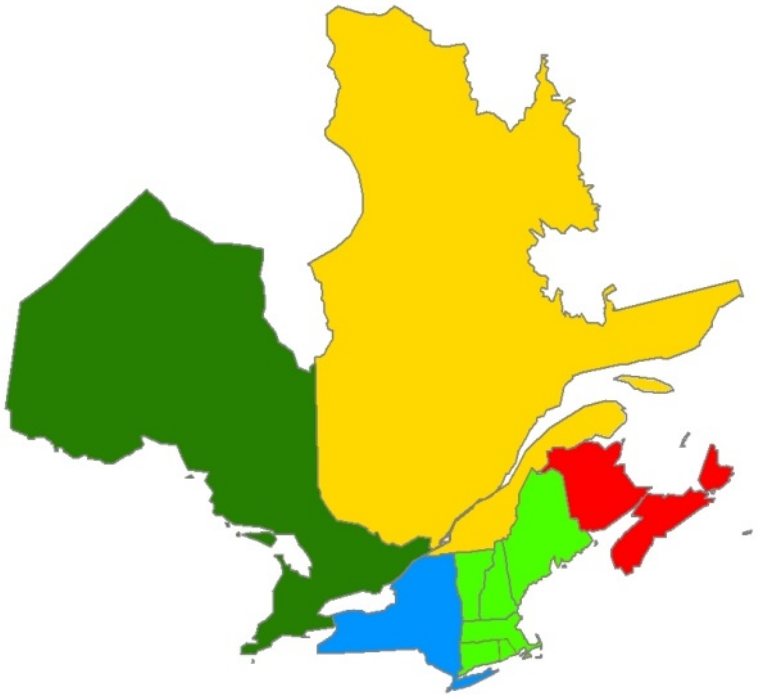
[3] Business Continuity Reserve (BCR) established in 2017 as approved by the NPCC Board of Directors to fund Succession Planning related expenses.

Explanation of Changes in Reserve Policy from Prior Year

There was no change to the existing Working Capital and Operating Reserve Policy. A separate Business Continuity Reserve (BCR) in the amount of $1,000,000 (allocated between the Regional Entity and Criteria Services divisions) was established in 2017 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 drawn upon as subsequently brought before the Board of Directors for approval of release of funds in association with President & CEO succession related activities associated with the planned or a sudden retirement, as well as other sudden changing workforce staffing requirements which could be brought about by coincident multiple staff retirements.

Section D – Additional Consolidated Financial Statements

2020 Business Plan and Budget



Section D — Additional Financial Statements

Statement of Financial Position

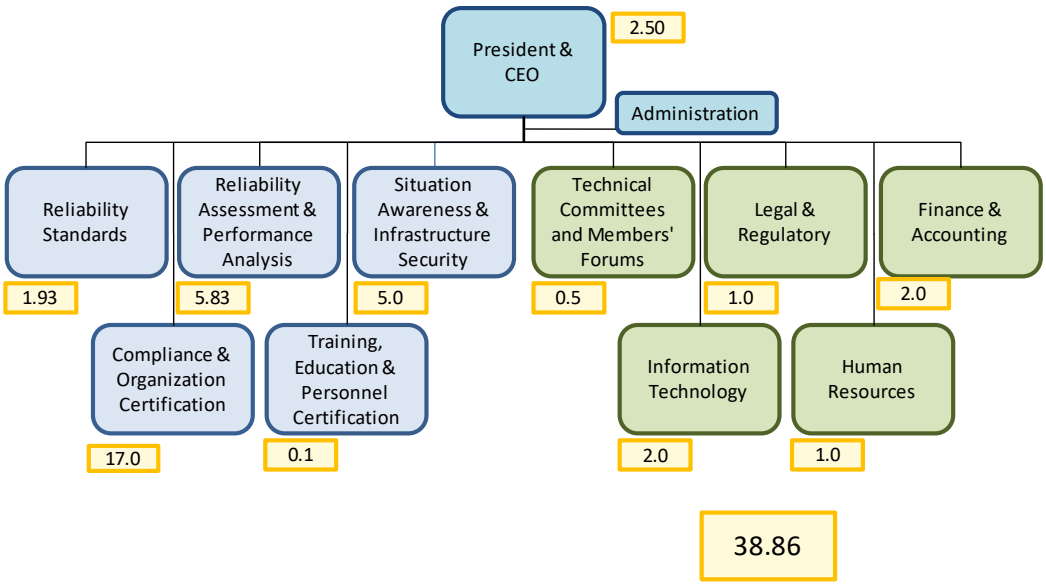
			Table to be Inserted				

Table to be Inserted

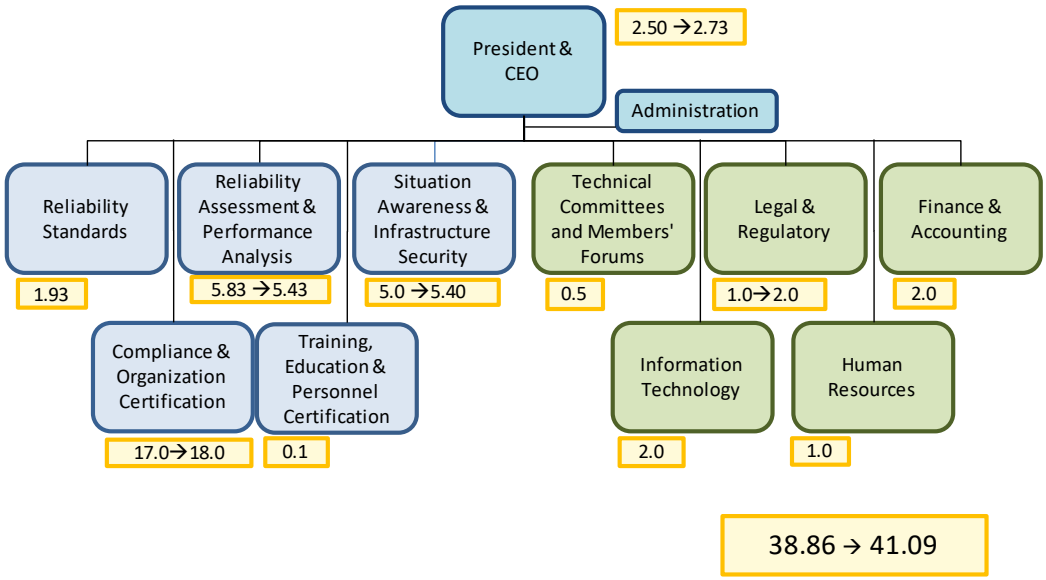
Table to be Inserted

Appendix A Staff Allocations

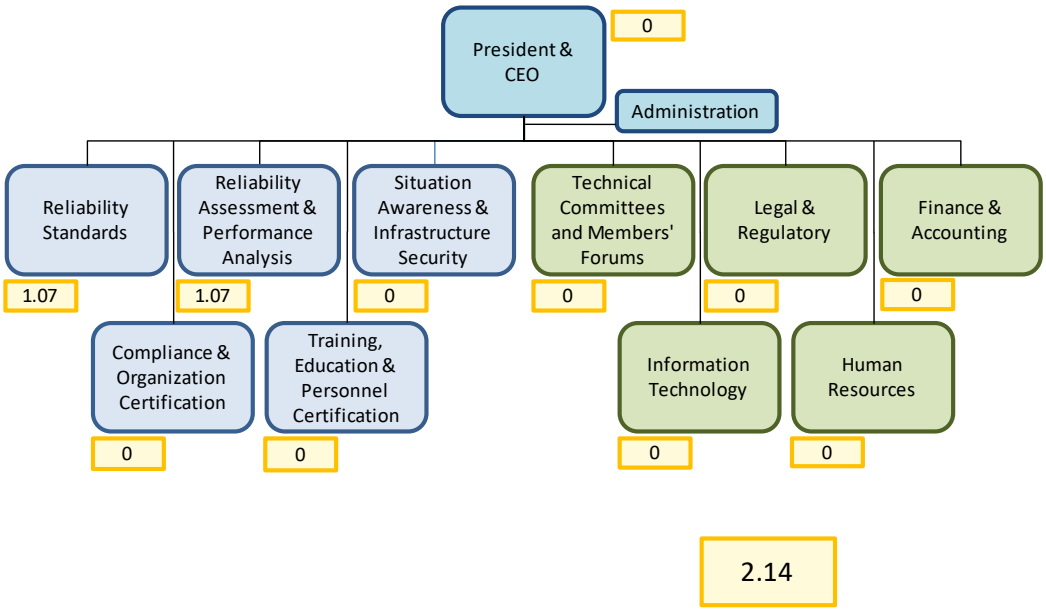
2019 Budget Staff Allocations - RE Division



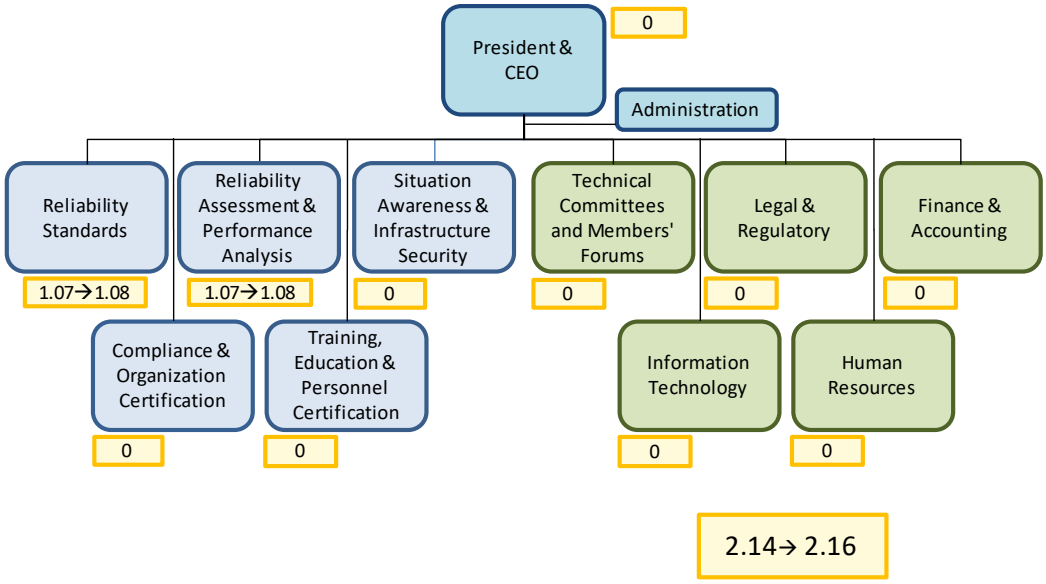
2020 Budget Staff Allocations - RE Division



2019 Budget Staff Allocations - CS Division



2020 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

Appendix C Index of Figures and Tables

Figure 1.	Budget by Program Area Chart	11
Table 1.	NPCC Budget	3
Table 2.	Budget by Program Area	11
Table 3.	Total FTE's by Program Area	12
Table 4.	Budget and Current Year Projection Comparison	13
Table A-1.	Reliability Standards Budget	15
Table A-2.	Reliability Standards Budget Detail	19
Table A-3.	Compliance Monitoring and Enforcement and Organization Registration and Certification Budget	20
Table A-4.	Compliance Monitoring and Enforcement and Organization Registration and Certification Budget Detail	25
Table A-5.	Reliability Assessments and Performance Analysis (RAPA) Budget	26
Table A-6.	Reliability Assessments and Performance Analysis (RAPA) Budget Detail	32
Table A-7.	Training, Education, and Operator Certification Budget	33
Table A-8.	Training, Education, and Operator Certification Budget Detail	36
Table A-9.	Situation Awareness and Infrastructure Security Budget	37
Table A-10.	Situation Awareness and Infrastructure Security Budget Detail	42
Table A-11.	Administrative Services Budget	43
Table A-12.	Administrative Services Budget Detail	44
Table B-1.	Working Capital Reserve Analysis	56
Table B-2.	Penalty Sanctions Received	57
Table B-3.	Supplemental Funding	58
Table B-4.	Personnel Expenses	59
Table B-5.	Meeting Expense	60
Table B-6.	Consultants and Contracts	60
Table B-7.	Office Rent	61
Table B-8.	Office Costs	61
Table B-9.	Professional Services	62
Table B-10.	Miscellaneous	62
Table B-11.	Other Non-Operating Expenses	62
Table B-12.	Fixed Assets	62
Table B-13.	Three-Year Projections	63
Table C-1.	Criteria Services Division Business Plan and Budget	65
Table C-2.	Budget and Current Year Projection Comparison	71
Table C-3.	Personnel Analysis	72
Table C-4.	Reserve Analysis	73
Table D-1.	Statement of Financial Position, Three-Year Comparison	75

NPCC, Inc.

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

NPCC Guidance Document, Approaches to Preserve System Resilience and Reliability for a High DER Penetration Future

NPCC Regional Standards Committee
Version 1 Approved August 7, 2019

NPCC, Inc.

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

Contents

Executive Summary 3
Introduction and Objective 4
NPCC Reliability Principles 6
NPCC DER Impact Reporting 8
DER BES Impact Considerations 9
NPCC Interconnection Guidance 10
- Voltage Response 11
- Frequency Support 12
- Reconnection to the Utility System 13
- Inverters 13
- Certification per UL 1741 SA as grid support utility interactive inverters 14
- Minimum Protective Functions 16
- Metering 18
- Power Quality 19
- Power Factor 19
- Islanding 19
- Underfrequency Load Shedding Programs 19
- Effective Grounding for DER 20
- Energy Storage Systems for DER 20
- System control and Data Acquisition (SCADA) and Communications 21

DER BES Recommendations 21
Appendix A NPCC DER Impact Reporting Form 23
Appendix B, NPCC Areas- Comparisons 25

Executive Summary

The Northeast Power Coordinating Council, Inc. (NPCC) is responsible for promoting and enhancing the reliability of the international, interconnected Bulk Power System in Northeastern North America.

As Distributed Energy Resources (DER), installed on the distribution system, continue to replace traditional industry generation resources, this transformation will impact the reliability and resilience of the Bulk Electric System (BES). Historically, the North American Electric Reliability Corporation (NERC) Reliability Standards have not been applicable to equipment on distribution systems unless such equipment has a direct impact on the reliable operation[1] of the BES such as UFLS. However, as penetration of DER increases, planning and operating assessments used to assure "Reliable Operation" of the BES will need to accurately represent how DER interacts with the BES.

Development of this document was initiated by the NPCC Board of Directors to develop Regional guidance for voluntary use by NPCC Members and stakeholders. The guidance provided herein identifies reliability risks[2] to the BES and suggests high level regional approaches NPCC Members could consider to reliably implement DER. Specifically, integration, capability, and operations issues which should be considered during process modification and development in their Area to maintain and continue to achieve reliable operation of the BES within NPCC.

This initial guidance does not consider specific rooftop solar or individual installations of wind turbines or other localized behind the revenue meter DER, although there is a process described in this document which allows entities to identify concerns regarding impacts to NPCC so they can be acknowledged and addressed in future versions of this document. NPCC Staff has developed this guidance in conjunction with NPCC Member input through the NPCC open comment process to highlight the importance of interconnection requirements at the distribution level. This document identifies opportunities for DER related process improvement and addressing potential reliability risks due to gaps that may exist, in order to promote good utility interconnection practices necessary for the reliability of the NPCC Region as a whole. In addition, during the development of this document, a review of existing DER related documents was performed and NPCC is working with the NY Interconnection Technical Working Group as well as the Joint Utilities group of NY to align processes where possible.

DER for the purpose of this guidance means any non-BES real or reactive resource (generating unit, multiple generating units at a single location, distributed generation, battery storage, etc.) located

[1] Reliable Operation is defined in 16 U.S. Code § 824o and means "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."

[2] An example of a reliability risk not addressed is remote dispatch of DER. A significant challenge that has been found by some NPCC members is that DER Operators can be anywhere in the world and that as a result, communications can be significantly delayed, leading to reliability risks. This includes time zone challenges and language challenges,

within the boundary of any distribution utility but not behind revenue metering, unless specifically indicated.

Detailed guidance provided by some NPCC Members is included in this guidance document for the benefit of Areas where DER interconnections have not yet progressed to high enough levels to warrant action in their Area. Since DER is a growing technology trend, all NPCC Members will benefit from seeing details on reliable DER integration which have been applied elsewhere. Their presence in this document does not indicate application within NPCC as a whole. Also it is important to note that specific NPCC Area or Utility requirements at the local level will supersede any suggested approaches in this document.

NPCC, at this time, is not creating new Criteria or Standards through this Version 1 document. The intent is purely informational and the document will need continual revisions as NERC and other groups develop their guidance documents to achieve continued alignment.

Introduction and Objective

As DERs continue to penetrate the electric system at the "grid edge" or distribution system, and replace conventional transmission grid connected resources, there is an increasing reliability related need to understand and influence the effect of these DER resources on the BES. It is important to understand how DERs are interconnected, planned, operated and how they interact with the transmission system.

Reliably and securely integrating DER into the electric system requires a comprehensive approach utilizing perspectives from areas, such as, DER design, modeling, planning, relay coordination, and especially requires consideration of jurisdictional issues and the importance of Members working with their respective national, state, and provincial regulatory authorities to help them understand the consequences of and formulation of effective DER interconnection requirements. While there may be some broad universal guidelines, the details of effective DER interconnection requirements should be reconciled with the nature of the system within which the interconnection is taking place. Appendix B of this document provides a comparison of NPCC's Area requirements, at the time of this Version 1 writing, to help identify opportunities for guidance.

Many, if not most, of the contemporary DERs are theoretically capable of bringing a number of enhancements to reliability, provided that there are sufficient design specifications and interconnection requirements to implement the enhancements. As an example, inverters, which convert direct current to alternating current, have microprocessor based control systems. These microprocessors operate with a very high internal clock speeds (on the order of MHz) and are capable of fine resolution frequency measurement. They are capable of electronically controlling the upward ramping of DER output and downwards ramping of DER output. Additionally settings in the DER inverters are capable of ceasing the injection of current into the electric system at very high speeds depending on control decisions. Inverters are capable of remaining physically connected (breaker closed) and not injecting current well in excess of normal 3-5 cycle breaker clearing times. This type of response can provide significant reliability benefits if control systems are properly configured to reliably implement it. Additionally, for

upward ramping, the distribution level connected resource should be available and operate with "headroom." In order to realize the benefits which DER are capable of to enhance reliability, it is important to understand the hosting capacity of the distribution system feeders where they are being located and the DER's expected capabilities, capacity, and operation. In addition to improving system response, DER in certain circumstances may enhance Resilience[3] by decentralizing generation and affording flexibility during restoration beyond that of normal system restoration plans but initially will also complicate system restoration plans[4]. Many utilities across North America are not including any DER in their system restoration to their variability and leaving them disconnected until such time as the system has been restored to a stable state. As DER penetration continues to increase and fossil fuel units retire it will create a need to revisit system restoration and Blackstart.

While DER present opportunities to enhance reliability, they also introduce challenges at the transmission/distribution interface. Interoperability with the transmission system is not solely determined at the point of interconnection. System needs such as visibility of generation state is essential for transmission operators to maintain situational awareness for operations purposes, for forecasting and integrated system planning to ensure reliability is maintained. Presently there are no study tools in general use to perform fully integrated studies of transmission and distribution which would allow both systems to be modeled and studied (in steady state and dynamically) together, although work is underway in this regard.

In recognition of both benefits and challenges, the approach taken with this first Version of the NPCC DER guidance document was to collect interconnection requirements within the NPCC Region as well as in other areas of the NERC Electric Reliability Organization (ERO) Enterprise. There are some specific issues where opportunity exists to ensure better coordination across the NPCC Region. The intent of this document is to identify risks and establish guidance, where possible, for interconnection of DER and raise awareness of opportunities. NPCC hopes to leverage any existing Area or distribution owner requirements in the Region. This is a first step to developing a NPCC Region-wide approach to interconnecting DER to distribution systems and reliably operating DER in conjunction with the BES. It is recognized that DERs may not be placed optimally and in areas where deliverability to load may not be ideal. In this respect any specific recommendations in this document will be subject to the requirements of the interconnecting distribution utility.

Presently there are no study tools in general use that allow utilities to perform fully integrated and simultaneous system studies of both the transmission and distribution systems, although work is underway in this regard. This is a current reliablity risk that is not adressed in this guidance document[5].

[3] Resilience as used in the guideline is referring to the 2018 NERC RISC Resilience Report

[4] Another example of a reliability risk not addressed is use of DER in system restoration. Specific issue as once voltage presence and frequency are returned, DERs will resync to the Grid without contact to the Control Center. Trying to maintain that balance of Generation and load during restoration path execution without integrating DER into the restoration Plan is challenging.

[5] NERC appears to currently suggest that studies modeling a few details at the T-D interface is sufficient. NPCC is considering proposing that more detailed and coordinated studies between transmission and distribution are needed.

NPCC Reliability Principles

Using its membership structure and governance authority to create and apply Regional Criteria[6], NPCC Member adherence to Regional criteria contributes to a more robust level of reliability beyond NERC ERO reliability "results-based" standards / requirements. For example, NPCC Criteria mandate specific design requirements for NPCC Member facilities. NPCC's approach to reliability and Resilience can be summarized in Principles that guide NPCC Members in their effort to meet or exceed NERC requirements. NPCC's core Reliability Principles[7] and activities support the NERC Bulk Electric System and NPCC's Bulk Power System reliability.

The NPCC Reliability Principles include:

1. **Focus on the most important system components**: In order to focus resources to those portions of the power delivery system most important (critical) to overall reliability, NPCC Members employ mechanism(s) for identifying those facilities that are most critical to the reliable planning and operation of the power delivery assets in the NPCC region[8]. These critical facilities collectively are identified as the NPCC Bulk Power System[9,10].
2. **Application of Criteria beyond NERC requirements to identified critical facilities**: Where, in the opinion of NPCC's Membership, the NERC standards do not adequately specify a necessary performance or design outcome in a given technical, operation or planning area, NPCC Criteria govern the design of their respective portions of the NPCC Bulk Power System planning and operation[11] activities.
3. **NPCC Members support the Criteria**: NPCC's Full Members in accordance with the NPCC Bylaws are committed to designing and operating their systems to meet the NPCC Criteria under peer review of the NPCC Full Members.
4. **No conflict with NERC Requirements**: The NPCC Criteria supplement, improve upon where necessary, benefit, and do not conflict with or duplicate the results-based performance

[6] See NERC Rule of Procedure #313 on page 15 of the NERC Rules of Procedure 3-9-2018.
[7] The Reliability Principles were summarized in the NPCC 2018 Strategic Review Report.
[8] The method of identifying critical facilities is currently embodied in the NPCC A-10 Classification of bulk power system Elements document, currently under review by the CP-11 Working Group with a due date of October 31, 2018.
[9] The NPCC bulk power system is identified by a specific list of facilities in the NPCC region deemed critical by the NPCC A-10 classification process. This list is not determined based on the definition of the ERO bulk power system, which is defined in the US 2005 EPACT as:
''(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and
''(B) electric energy from generation facilities needed to maintain transmission system reliability.
The term does not include facilities used in the local distribution of electric energy.
[10] There are other documents which supplement the Directories, for instance the NPCC Compliance Guidance Statements. These documents usually refer to NERC standards applicability and can be found here: NPCC CGS
[11] NERC Rule of Procedure #313 (page 15) permits the following: "Regional Entities may develop Regional Criteria that are necessary to implement, to augment, or to comply with NERC Reliability Standards, but which are not Reliability Standards. Regional Criteria may also address issues not within the scope of Reliability Standards, such as resource adequacy. "

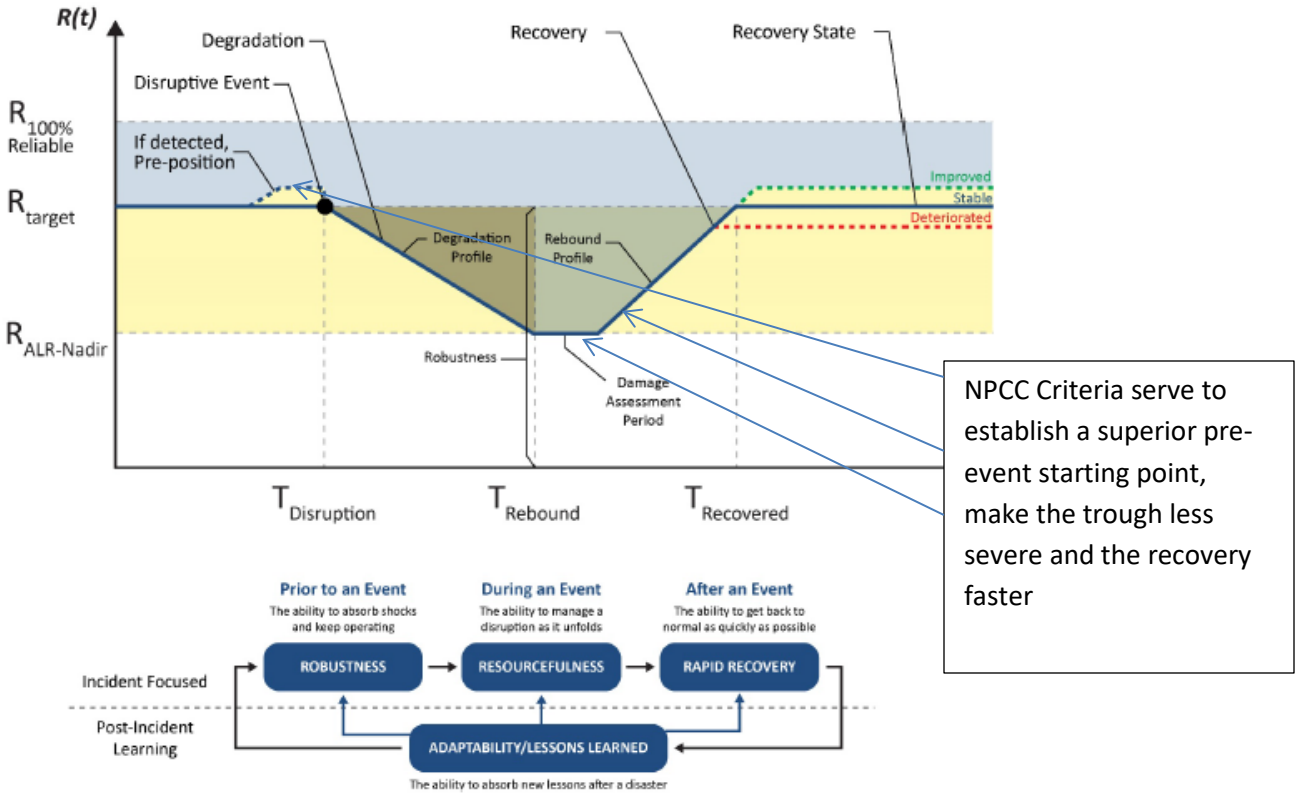
requirements of NERC standards where they apply to the NPCC Bulk Power System. NPCC adjusts its regional Criteria to retire or adapt to any new NERC requirements as they come into effect as necessary.

5. **Include design specifications where needed**: The NPCC Criteria and related guidelines and procedures provide design criteria and practices to assure implementation. NPCC Directories go into greater detail regarding how to accomplish a given reliability result, where NERC standards may simply require a "reliability result."
6. **Resilience has always been an element of NPCC Criteria:** Based on experience, resilience[12] [13] is a necessary constituent component of reliability and it is important both to electricity consumers and regulatory authorities in NPCC's Region. NPCC Criteria provide substantial resilience benefits to the NPCC Bulk Power System by providing:
    a. Robustness – The ability to withstand disturbances by supporting operations in a more secure state.
    b. Resourcefulness – The ability to detect and manage a crisis as it unfolds.
    c. Rapid recovery – The ability to get services back as quickly as possible in a coordinated and controlled manner.
    d. Adaptability – The ability to absorb new lessons from events.

[12] Reference NERC's recent filing with FERC regarding Resilience for a more complete discussion of the relationship between resilience, the NERC standards and the NAICS Resilience Framework. FERC is expected to define resilience in the course of its current examination of electric system resilience concepts.

[13] In the US, Presidential Policy Directive – 21 defines resilience as "The ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents".

NERC RISC Model of Resilience



NPCC Criteria serve to establish a superior pre-event starting point, make the trough less severe and the recovery faster

Figure 2.1

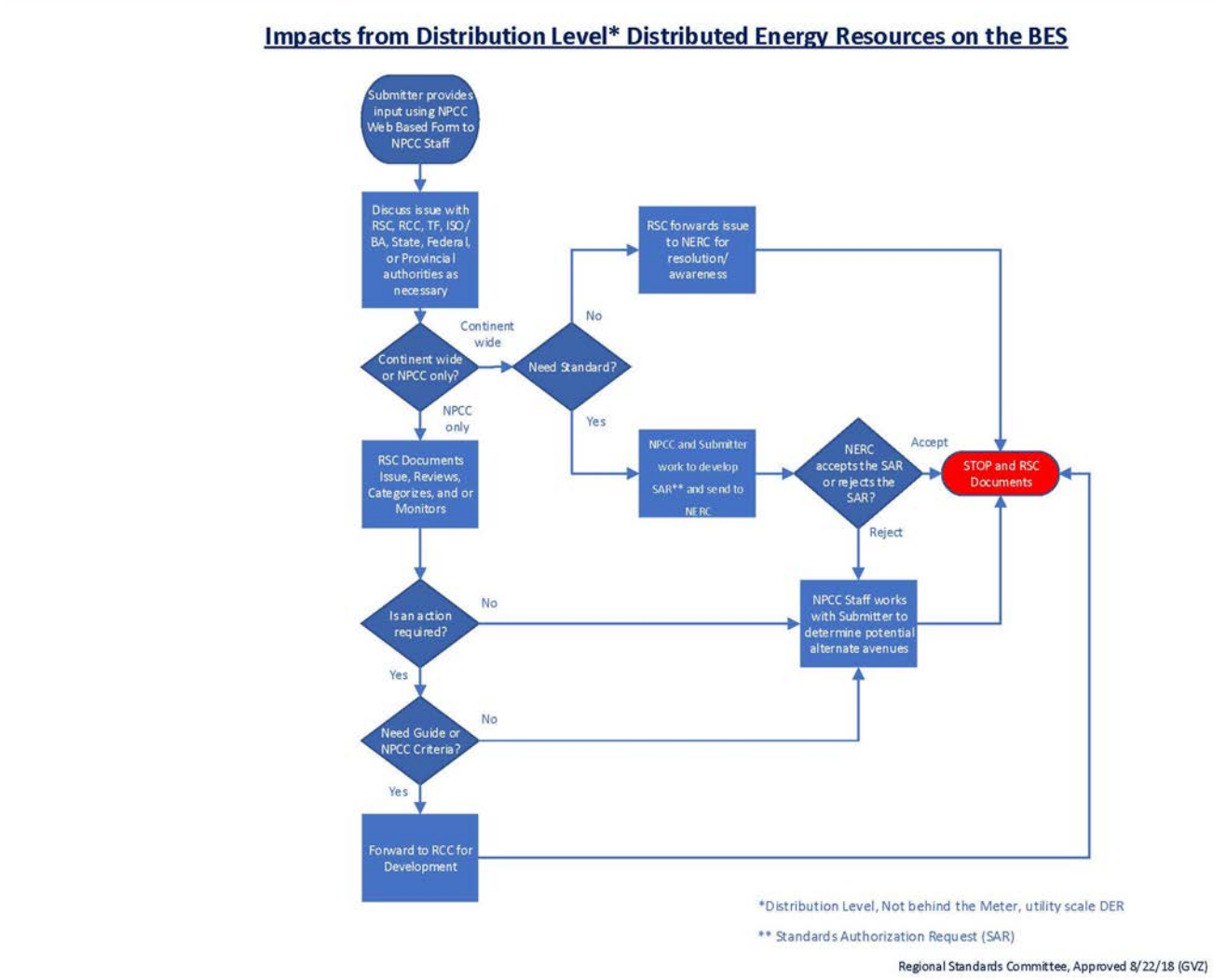
Also recognize the critical role that DER will have with respect to reliability and Resilience of the Bulk Electric System. Specifically, DER can contribute to the overall robustness of the system and provide increased resource support within islands during system separations. As DER continues to penetrate the system, changes to NPCC's Underfrequency Load Shedding program may be required.

NPCC DER Impact Reporting

In order to ensure the reliability and Resilience of the interconnected BES in Northeastern North America as DER continues to proliferate throughout the distribution systems within the NPCC Region, it is important to have a centralized DER impact reporting mechanism. The NPCC Regional Standard Committee (RSC) created an impact reporting form and process that allows entities to report DER impacts and to seek guidance regarding emerging issues and reliability risks that affect or could affect the reliable performance of the BES see Appendix A. The Word version of the below form resides on the NPCC website at:

BES Impact Reporting Form

Impact reporting and its associated process provide an orderly mechanism for NPCC to review reliability impacts submitted and will initiate a collaborative review by the Reliability Coordinating Committee and Regional Standards Committee. The process is shown below.



DER BES Impact Considerations

NPCC's Regional Standards Committee (RSC) and Task Forces (i.e. Task Force on System Studies and impacts on UFLS) reviews of DER as it pertains to the NPCC Region's BES performance have identified a number of areas which, going forward, may warrant further and continual monitoring and analysis. NPCC has identified the following items that should be carefully considered as DER levels (total MWs) increase.

- DER performance with respect to voltage and frequency ride through as well as the ability to provide regulation and reserves

- DER availability and quality of forecasting.
- Observability and situational awareness of DER
- DER impacts on Underfrequency Load Shed programs.
- Effects of harmonics produced by non-linear device based DERs (e.g. inverters) on the power system.
- Impacts of DER on System Restoration and Black Start Plans.
- DER Markets: Encouraging identification of Points of Common Coupling transmission nodes affected and injection to where DER is best utilized and the appropriate DER output levels. Some Areas currently allow aggregation across a broad area while others require aggregation to specify at which transmission node the aggregated injection will occur.

NPCC Interconnection Guidance

This document and any detailed specifications which follow, are intended to be examples of interconnection guidance and do not constitute a Regional Criteria which can only be implemented (if at all) through NPCC Directories. There are numerous efforts underway in many forums and regulatory bodies that are expected to create new, more specific guidance[14]. The level of detail and specificity provided is intended to be used as guidance for any NPCC Member Area which may not have yet seen the need to establish detailed operating parameters. Some Members of NPCC have already established detailed DER requirements, even in advance of upcoming applicable industry standards due to the rate of penetration of DER in their Area. NPCC Members considering improving or adding to their respective DER guidance are encouraged to reach out directly to other members which may have already addressed DER related reliability risk issues.

As general considerations, the DER owner should be encouraged to provide appropriate protection and control equipment, including a protective device and communications system that utilizes an automatic disconnecting device which will disconnect the generation under various conditions (for example, in the event that the portion of the utility system that serves the generator is de-energized for any reason, or for a fault in the generator-owner's system). There is also the possibility of over generation as has been demonstrated in CA, when the system operator runs out of load to absorb the available generation. Operating procedures for selecting which generation to curtail should be in place therefore System Operator visibility is necessary. In lieu of visibility and operating procedures, some areas of the country are planning to use market mechanisms to address this issue. The DER owner's protection and control equipment also should be capable of automatically disconnecting the generation from the system to which it is connected upon detection of a utility system fault.

The DER owner's protection and control scheme should be designed to ensure that the generation remains in operation when the frequency and voltage of the utility system is within the limits specified

[14] At the time of this guidance document development, these include but are not limited to: NERC (e.g. SPIDER WG, IRPTF, Events Analysis, Modelling and Standards process), IEEE (IEEE 1547, P2800), and various state initiatives such as the New York ITWG, Other Regional initiatives.

by the interconnecting utility and its required operating ranges. Upon request from the interconnecting utility, the DER owner should be prepared to provide documentation detailing conformance with the guidance set forth in the connecting utility requirements.

The specified size of the generation facility or energy storage system should be based on electrical generator or inverter AC nameplate ratings. The specific design of the protection, control, and grounding schemes will depend on the size and characteristics of the DER owner's generation, as well the DER owner's expected load level. Dynamic protection systems may be needed based the characteristics of the particular portion of the utility's system where the DER owner is interconnecting.

The DER owner should have, as a minimum, an automatic disconnect device(s) sized to meet all applicable local, state, and federal codes and operated by over and under voltage and over and under frequency protection. For three-phase installations, the over and under voltage function should be included for each phase and the over and under frequency protection on at least one phase. All phases of a generator or inverter interface should disconnect for appropriate voltage or frequency trip conditions sensed by the protective devices. Voltage protection should be wired phase to ground for single phase installations and for applications using wye grounded-wye grounded service transformers.

The settings referenced herein are generally intended for single-phase and three-phase applications using wye grounded- wye grounded service transformers or wye grounded-wye grounded isolation transformers. For applications using other transformer connections, a site-specific review should be performed by the utility and the revised settings identified in the DER Application Process[15].

The guidance set forth in this document are intended to be consistent with those specifications contained in the most current version of IEEE Standard 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems. It is recommended that the requirements in IEEE 1547 above and beyond those contained in this document or the interconnecting utility requirements, are to be followed including any other Standards referenced to in IEEE Std. 1547.

Voltage Response

Operating range for the generators is generally intended to be from 0.88 to 1.10 per unit of nominal voltage magnitude. In addition, the generator should not cause the system voltage, at the Point of Common Coupling (PCC), to deviate from a range of 0.95 to 1.05 per unit of the utility system voltage. Historically for excursions outside these limits the protective device generally automatically initiates a disconnect sequence from the utility system as detailed in the most current version of IEEE Std. 1547. Clearing time is defined as the time the range is initially exceeded until the DER owner's equipment ceases to energize the PCC and includes detection and intentional time delay. Other static or dynamic voltage functionalities may be permitted as agreed upon by the utility and DER owner. The industry is

[15] At this time there has not been an assessment of potential change in sensitivity (increase or decrease) to the effects of GMD from the presence of high DER penetration. This is a potential reliability risk to be evaluated in the future.

now in the process of changing this approach to promote ride-through via a number of different standards initiatives which NPCC is tracking through its DER Forum.

Example of Alternative Approach to promote ride-through

Ensuring that DERs are able to respond appropriately for various voltage conditions is critical for system reliability, as well as avoiding equipment damage and protecting personnel safety. Continuous operation over a wide band of voltage levels will ensure that DERs do not prematurely trip and further deteriorate system conditions. Appropriate tripping for voltages related to temporary fault conditions will also help maintain system reliability.

Quebec Interconnection

Ride through is of primary importance for resources connected to the grid, with the objective of maintaining system reliability. IEEE-1547 addresses the topic, however, for voltage and frequency, what is required in the IEEE standard does not match the requirements in Quebec. For example, in under frequency, HQ's requirement goes as low as 55.5 Hz (for a short time period) while IEEE-1547 does not require mandatory operation below 57 Hz.

DER should have voltage related operational capability and protection settings set as prescribed by the area Electric Power System (EPS) operator and in accordance with IEEE Std. 1547-2018.

This subject area is a matter of facility installation and personnel policy of the asset owner, balancing both reliability and safety.

In the Quebec interconnection voltage ranges and regulation requirements vary from the Eastern Interconnection. The requirements of the local authority having jurisdiction should be followed (typically Hydro Quebec).

Frequency Support

Frequency support is provided through the combined interactions of synchronous inertia and frequency response. Working in a coordinated way, these characteristics and services arrest the decline in frequency after a disturbance and eventually return the frequency to the desired level. As increased levels of DER are introduced to the system, synchronous inertia will be displaced, which may have an impact on the frequency response performance of the system. With increased penetration of DER it is becoming desirable for DER to remain connected even outside the prescribed frequency range if there is no risk to the DER equipment. The ride-through curves are "shall not trip above the curve," not "must trip below the curve. Regarding frequency operating characteristics of Inverters:

The operating range for the DER distribution connected resources should be similar to that of BES connected resources. The operating band for frequency of a DER resource's operating range should be at least from 59.3 Hz to 60.5 Hz as required by the latest versions of NPCC's PRC-006 and NERC PRC-024 UFLS standards. If deemed necessary, the utility may request that the generator operate at frequency ranges below 59.3 Hz in coordination with the current under frequency load shedding schemes of NPCC and the local utility system. For excursions outside these limits the protective device should

automatically initiate a disconnect sequence from the utility system as detailed in the most current version of IEEE 1547. Clearing time is defined as the time the range is initially exceeded until the DER owner's equipment ceases to energize the PCC and includes detection and intentional time delay. Other static or dynamic frequency functionalities may be permitted as agreed upon by the utility and DER owner. There may be a need to establish a mechanism to formally have TO/DP's provide information as to which DER facilities are connected to feeders that have UFLS protection systems.

In addition, the 59.3 Hz from the UFLS system performance curve within which system frequency should remain (e.g. PRC-006-3). This curve may not be the best source for setting frequency characteristics for generators. There are other standards that have frequency trip curves for generators (e.g. IEEE 1547, PRC-024-2, NPCC-006-NPCC-1 and NPCC D12). Note that the generator frequency trip curves may have a continuous operating range that is lower than 59.3Hz (e.g. 59 Hz in NPCC Directory 12 and PRC-006-NPCC-1).

Quebec Interconnection

Note that in the Quebec Interconnection the frequency operating range is wider than in the Eastern Interconnection. In Quebec, the acceptable frequency range is from 59.4 Hz to 60.6 Hz therefore in Quebec, UFLS systems must operate outside this operating rang in accordance with the Quebec variance to the PRC-006-NPCC UFLS-1 regional standard table 4.

Reconnection to the Utility System

If the generation facility is disconnected as a result of the operation of a protective device, the DER owner's equipment should remain disconnected until the utility's service voltage and frequency have recovered to acceptable voltage and frequency limits for an acceptable amount of time as specified in the most current version of IEEE Std. 1547. Under IEEE Std. 1547 output is to be restored in 0.4 seconds.

Systems greater than 25 kW that do not utilize inverter based interface equipment should not have automatic recloser capability unless otherwise approved by the utility. If the interconnecting utility determines that a facility must receive permission to reconnect, then any automatic reclosing functions must be disabled and verified to be disabled during verification testing.

Utilities in other parts of the Eastern Interconnection who have experienced increased levels of DER have determined that during system restoration, DER should not be allowed to return to service until the system has been reestablished and is in a stable operating state. As traditional resources on the BES are retired and the grid becomes increasingly reliant on grid edge DER on the distribution, Black Start and System Restoration plans will have to be adjusted accordingly.

Inverters

Direct current generation can only be installed in parallel with the utility's system using a synchronous inverter. The design should be capable of disconnecting the synchronous inverter upon a utility system event. Inverters intended to provide local grid support during system events that result in voltage and/or frequency excursions as described in this document and should be provided with the required onboard functionality to allow for the equipment to remain online for the duration of the event.

It is recommended that all applicable inverter-based applications should:

- be certified per the requirements of UL 1741 SA as a grid support utility interactive inverter
- have the voltage and frequency trip settings as specified by the interconnecting utility
- have the abnormal performance capabilities (ride-through)
- provide interactive inverter functions status

In New York State it is recommended that equipment be selected from the Department of Public Service "Certified Interconnection Equipment list" maintained on the NY Public Service Commission's website. Interconnected DG systems utilizing equipment not found in such list should meet all functional requirements of the current version of IEEE Std. 1547 and be protected by utility grade relays (as defined in these requirements) using settings approved by the utility and verified in the field. The field verification test in New York State must demonstrate that the equipment meets the voltage and frequency requirements detailed in this section.

Synchronization or re-synchronization of an inverter to the utility system should not result in a voltage deviation that exceeds the local utility or authority having jurisdiction power quality requirements. Only inverters designed to operate in parallel with the utility system should be utilized for parallel operation.

Certification per UL 1741 SA as grid support utility interactive inverters

Because Inverters certified for IEEE 1547-2003 do not currently provide adequate grid support functionality, in the interim period while IEEE P1547.1 is not yet revised and published, certification of all inverter-based applications is needed. For example, in one NPCC Area the following approach was taken to assure having inverters installed with a standardized set of grid support functionalities to ensure the reliability of the BES (e.g. maintaining acceptable system frequency and voltage).:

- Should be compliant with only those parts of Clause 6 (Response to Area EPS abnormal conditions) of IEEE Std. 1547-2018 (2nd ed.)1 that can be certified per the type test requirements of UL 1741 SA (September 2016).
- May be sufficiently achieved by certifying inverters as grid support utility interactive inverters per the requirements of UL 1741 SA (September 2016) with either CA Rule 21 or Hawaiian Rule 14H as the Source Requirement Document (SRD). Such inverters are deemed capable of meeting the requirements of this document.
- Applications should have the voltage and frequency trip points and abnormal performance capabilities consistent with IEEE 1547-2018, PRC-024-2 and PRC-006-NPCC.
- Abnormal performance capability (ride-through) requirements for inverter based applications should have the ride-through capability per abnormal performance category II of IEEE Std. 1547-2018 (2nd ed.) as quoted in Tables III and IV.

The following additional performance requirements are applied in one NPCC Area and are provided as an example:

- In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and

- In the Permissive Operation region below 0.5 p.u., inverters shall ride-through in Momentary Cessation mode.

Table I: Inverters' Voltage Trip Settings

Shall Trip – IEEE Std 1547-2018 (2nd ed.) Category II					
Shall Trip Function	**Required Settings**		**Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings for Category II**		
	Voltage (p.u. of nominal voltage)	**Clearing Time(s)**	**Voltage**	**Clearing Time(s)**	**Within ranges of allowable settings?**
OV2	1.20	0.16	Identical	Identical	Yes
OV1	1.10	2.0	Identical	Identical	Yes
UV1	0.88	2.0	Higher (default is 0.70 p.u.)	Much shorter (default is 10 s)	Yes
UV2	0.50	1.1	Slightly higher (default is 0.45 p.u.)	Much longer (default is 0.16 s)	Yes

Table II: Inverters' Frequency Trip Settings

Shall Trip Function	**Required Settings**		**Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings for Category I, Category II, and Category III**		
	Frequency (Hz)	**Clearing Time(s)**	**Frequency**	**Clearing Time(s)**	**Within ranges of allowable settings?**
OF2	62.0	0.16	Identical	Identical	Yes
OF1	61.2	300.0	Identical	Identical	Yes
UF1	58.5	300.0	Identical	Identical	Yes
UF2	56.5	0.16	Identical	Identical	Yes

Table III: Inverters' Voltage Ride-through Capability and Operational Requirements

Voltage Range (p.u.)	**Operating Mode/ Response**	**Minimum Ride-through Time(s) (design criteria)**	**Maximum Response Time(s) (design criteria)**	**Comparison to IEEE Std 1547-2018 (2nd ed.) for Category II**
V > 1.20	Cease to Energize	N/A	0.16	Identical
1.175 < V ≤ 1.20	Permissive Operation	0.2	N/A	Identical
1.15 < V ≤ 1.175	Permissive Operation	0.5	N/A	Identical
1.10 < V ≤ 1.15	Permissive Operation	1	N/A	Identical
0.88 ≤ V ≤ 1.10	Continuous Operation	infinite	N/A	Identical
0.65 ≤ V < 0.88	Mandatory Operation	Linear slope of 8.7 s/1 p.u. voltage starting at 3 s @ 0.65 p.u.: $T_{VRT} = 3\text{ s} + \frac{8.7\text{ s}}{1\text{ p. u.}}(V - 0.65\text{ p.u.})$	N/A	Identical
0.45 ≤ V < 0.65	Permissive Operation [a,b]	0.32	N/A	See footnotes a & b
0.30 ≤ V < 0.45	Permissive Operation [b]	0.16	N/A	See footnote b
V < 0.30	Cease to Energize	N/A	0.16	Identical

The following additional operational requirements can be used. Provided as an example:

a. In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and

b. In the Permissive Operation region below 0.5 p.u., inverters shall ride-through in Momentary Cessation mode with a maximum response time of 0.083 seconds.

Table IV: Inverters' Frequency Ride-through Capability

Frequency Range (Hz)	Operating Mode	Minimum Time(s) (design criteria)	Comparison to IEEE Std 1547-2018 (2nd ed.) for Category II
f > 62.0	No ride-through requirements apply to this range		Identical
61.2 < f ≤ 61.8	Mandatory Operation	299	Identical
58.8 ≤ f ≤ 61.2	Continuous Operation	Infinite	Identical
57.0 ≤ f < 58.8	Mandatory Operation	299	Identical
f < 57.0	No ride-through requirements apply to this range		Identical

Table V: Grid Support Utility Interactive Inverter Functions Status

Function	Default Activation State
SPF, Specified Power Factor	OFF[2]
Q(V), Volt-Var Function with Watt or Var Priority	OFF Default value: 2% of maximum current output per second
SS, Soft-Start Ramp Rate	ON
FW, Freq-Watt Function OFF	OFF

Minimum Protective Functions

Protective system requirements for distributed generation facilities result from an assessment of many factors, including but not limited to:

- Type and size of the distributed generation facility
- Voltage level of the interconnection
- Location of the distributed generation facility on the circuit
- Distribution transformer
- Distribution system configuration
- Available fault current
- Load that can remain connected to the distributed generation facility under isolated conditions
- Amount of existing distributed generation on the local distribution system.

It is not possible to standardize protection requirements according to any single criteria. At a minimum, the protective function guidance in Table VI below should be considered. Function numbers, as detailed in the latest version of ANSI C37.2, are listed with each function. All voltage, frequency, and clearing time set points are should be field adjustable.

Table VI: Grid Support Minimum Protective Functions

Synchronous Generators	Induction Generators	Inverters
Over/Under Voltage (Function 27/59)	Over/Under Voltage (Function 27/59)	Over/Under Voltage (Function 27/59)
Over/Under Frequency (Function 81O/81U)	Over/Under Frequency (Function 81O/81U)	Over/Under Frequency (Function 81O/81U)
Anti-Islanding Protection	Anti-Islanding Protection	Anti-Islanding Protection
Overcurrent (Function 50P/50G/51P/51G)	Overcurrent (Function 50P/50G/51P/51G)	Overcurrent (Function 50P/50G/51P/51G)

For energy storage systems or distributed generation where net export is limited, Reverse Power (Function 32) should be considered.

The need for additional protective functions will be determined by the utility on a case- by-case basis. If the utility determines a need for additional functions, it will notify the DER owner of the requirements. The notice should include a description of the specific aspects of the utility system that necessitate the addition, and ideally, explicit justification for the necessity of the enhanced capability. The connecting utility will specify and provide settings for those functions that the utility designates as being required to satisfy their individual protection practices. Any protective equipment or setting specified by the utility is not to be changed or modified at any time by the DER owner without consent from the utility.

The DER owner is responsible for ongoing compliance with all applicable local, state, and federal codes and standardized interconnection requirements as they pertain to the interconnection of the generating equipment. Protective devices should utilize their own current transformers and potential transformers and not share electrical equipment associated with utility revenue metering.

A failure of the DER owner's protective devices, including loss of control power, should open the automatic disconnect device, thus disconnecting the generation from the utility system. For example, if the DER protection is powered off the system AC, and there's a disturbance that drives voltage to go too low and the control/protection loses power which then trips the DER, then the DER wouldn't be meeting the necessary ride-through requirements. A DER owner's protection equipment should utilize a non-volatile memory design such that a loss of internal or external control power, including batteries, will not cause a loss of interconnection protection functions or loss of protection set points.

All interface protection and control equipment should operate as specified, independent of the calendar date.

For monitoring and control of new DG projects, the most current version of the Monitoring and Control Criteria should be employed by the utilities to evaluate the need for such equipment in New York and considered in the NPCC region if no other local criteria are available. The New York Monitoring and Control Criteria document was developed and agreed to through a collaborative process as part of the Interconnection Technical Working Group (ITWG)[16]. The communications hardware, protocols, and data models must comply with local interconnection utility standards.

Also and fundamentally, existing over-current protections in distribution system are typically designed to clear line and ground faults occurring downstream from their location, as the source feeding the fault is only the transformer station. Connecting a DER provides another source supplying the fault, and the fault contribution from the facility might cause protection to operate non-selectively for reverse faults, out of the protected zone. If the maximum reverse fault current through a non-directional fault-interrupting device exceeds the setting of the device, the fault-interrupting device should be considered with a directional feature to prevent tripping for reverse fault current flow. For instance, phase protection could be replaced with an impedance relay (function 21) if required.

Metering

Metering requirements for SCADA purposes are determined by the local connecting utility and based on the configuration of the DER system prior to energization. Whether SCADA metering can be integrated with revenue metering is a matter for the local connecting utility and connecting DER facility to decide. New metering or modifications to existing metering should be reviewed on a case-by-case basis and be consistent with metering requirements specified by the local connecting utility and any overarching requirements adopted by the local regulatory authority that has jurisdiction (e.g. state commission for example for revenue metering). Net Energy Metering is permitted should be installed when a DER has the capability or potential to provide generation back into the utility distribution system, however, the eligibility of a DER provider to receive net metering will be subject to the rules of the interconnecting utility and the local regulatory authority that has jurisdiction .

A DER should be capable of providing monitoring of connection status, real power output, reactive power output, and voltage either at the point of connection or some agreed upon point if multiple DER facilities are involved. This information should be available to the system operator as required by the connecting utility. The monitoring equipment should be installed at the time of interconnection and meet the technical requirements of the connecting utility. The DER metering and monitoring communications will allow interoperability and the capability to provide system operators with situational awareness necessary for reliably operation of the interconnecting utility facilities. As more DER is employed and base load generation is replaced with DER resources, it will be important for the

[16] This document can be found on the Department of Public Service website (www.dps.ny.gov) at the Distributed Generation/Interconnections tab under Interconnection Technical Working Group Information.

Distribution Provider (DP) or interconnecting utility to be able to monitor the availability and production of electricity (power output and energy delivered) from the DER resources.

Power Quality

The requirements for acceptable flicker levels should be in accordance with the latest version of IEEE Std. 1453 Recommended Practice for the Analysis of Fluctuating Installations on Power Systems. Short and long-term perception of flicker should be within the planning and compatibility levels delineated in any applicable requirements or standards.

Power Factor

If the output power factor, as measured at terminals of the generator, is less than 0.9 (leading or lagging), the method of power factor correction necessitated by the installation of the generator can be negotiated with the utility as a commercial item. If the average power factor of the DER over time is proven to be outside the 0.9 (leading or lagging) by the customer and accepted by the utility, that power factor range may be used for any further utility facility design calculations and requirements.

Induction power generators may be provided with a VAR capacity from the utility system. The installation of VAR correction equipment by the generator- owner on the DER owner's side of the PCC is to be reviewed and approved by the interconnecting utility prior to installation.

Islanding

Systems should be designed and operated so that islanding is not sustained on utility distribution circuits or on substation bus and transmission systems. The guidance provided in this document is designed and intended to avoid islanding and is subject to be superseded by local requirements. Special protection schemes and system modifications may be necessary based on the capacity of the proposed system and the configuration and existing loading on the subject circuit.

The need for zero sequence voltage and direct transfer trip protection schemes should be evaluated based on minimum loads on the associated feeder and substation bus, including the impact of fault conditions resulting from DER installation to protect facilities for an islanded condition.

Transfer trip is needed in some instances (e.g. on DER connections to non-radial transmission or sub-transmission circuits) in order to protect the utility systems and DER facility from damage during faults and/or reclosing operations into faults. The decision as to the applicability of direct transfer trip and specific technology to be used form direct transfer trip communications rests with the connecting utility.

Underfrequency Load Shedding Programs

Underfrequency Load Shedding (UFLS) is implemented to restore power system frequency stability if system frequency drops below the UFLS operational set point. Significant deviations in system frequency typically occur during major disturbances such as a loss of generation or events in excess of design contingencies used for planning purposes. UFLS is considered the "safety net" for the BES and a last resort automatic control operation designed to stabilize BES islands for a generation deficiency. Various fractions of load are shed through this process, typically 25%. UFLS is primarily installed on distribution feeders, where DER is increasingly being deployed.

NERC has a set of requirements in the PRC-006 standard and NPCC has more stringent requirements in NPCC's Regional Standard, PRC-006-NPCC which outline expected UFLS performance. Approved and effective versions of these standards may both be found on the NERC website.

SS-38 is the NPCC working group responsible for inter-Area dynamic analysis. The SS-38 Working Group regularly studies the UFLS performance within the Region and has recently determined, through sensitivity analysis, that increased levels of DER penetration anticipated in the short term will not result in any significant degradation in UFLS performance.

Adopting a more flexible approach to UFLS may be necessary as DER penetrations reach higher levels. There are utilities that are reviewing the feasibility of "Adaptive UFLS" which uses real time monitoring of distribution feeder loads and their DER to determine how much additional load may need to be tripped when DER has increased output.

Effective Grounding for DER

With the onset of high penetrations DER, such as photovoltaic (PV) generation, utilities should consider interconnection of PV plants similarly to how they would interconnect synchronous generators. Conventional generators are considered to be voltage sources as they provide constant AC voltages controlled by excitation systems. In contrast, an inverter-based DER plants are considered as current sources, and the DER terminal voltage is dependent on the feeder to which it is connected.

Solidly grounding a transformer neutral for a DER plant eliminates a possible phase overvoltage stemming from a single-line-to-ground fault. A potential problem with the solid grounding in the distribution line is that large fault currents can flow through the transformer neutral, which can desensitize the overcurrent protection coordination. In order to mitigate this issue, impedance grounding can limit the fault current and potential equipment damage, while allowing overvoltage to some limited magnitude. Some utilities protect their distribution from overvoltage by using overvoltage protection so Effective Grounding isn't a concern. Further investigation on the how specific installations are grounded is warranted and being pursued by the Interconnection Technical Working Group (ITWG) in New York.

Energy Storage Systems for DER

Battery storage technology is undergoing a rapid evolution from Lead Acetate to Absorbent Glass Mat to Li-Ion due to the expanding application of batteries to transportation and other sectors. Li-Ion batteries have been and continue to be deployed in a wide range of electric energy-storage applications, ranging from energy-type batteries of a few kilowatt-hours in residential systems with rooftop photovoltaic arrays to multi-megawatt containerized batteries for the provision of grid ancillary services. The Energy Storage Association (ESA) anticipates at least 35 GW of new energy storage will be deployed in the United States by 2025 and that the amount of energy storage will double from 2018 levels during 2019.

The ESA in conjunction with over 25 vendors and utilities have formed a task force and made a commitment to optimize safety standards. Care should be used in placement of batteries. Suggested placements should avoid proximity to other facilities that may be critical to the reliability of the BES.

System control and Data Acquisition (SCADA) and Communications

As DER penetration increases and all DERs above a certain MW level, as determined by the interconnecting utility or System Operators, should be required to provide SCADA telemetry data to the control center to monitor their output. IEEE-1547-2018 has a communication port requirement. This ensures that the output remains visible to the system operator. It allows the system operator to observe DER status when working on a feeder in emergent or planned situations. Some NPCC Members have encountered difficulty with getting compliance on this need from the DERs. DER owners should be encouraged to keep their end of any SCADA equipment functional and reconnect their telemetry devices when they have been disabled and this can be done through interconnection requirements. The operator should be alerted by the DER when telemetry is interrupted. Scan rates equivalent to the scan rates used by the system operator are preferred (typically 6 second).

DER BES Recommendations

As DER continues to penetrate the NPCC Region we suggest the following initial activities:

Process and Risk Management Recommendations

1) Continue with sensitivity analysis at the Transmission level for various levels of penetration of DER on distribution facilities to determine effects of increased penetration levels of DER on UFLS performance.
2) Pursue further opportunities to coordinate distribution and transmission requirements for DER generating resources and promote NPCC Regional consistency where possible.
3) Continue to review NPCC Area authorities having jurisdiction and utility interconnection relative to DER requirements documents to identify dissimilarities between Areas which may negatively impact reliability.
4) Identify opportunities to share information regarding DER related reliability risk problems and problem solving.
5) Continue to solicit and address observable reliability issues of DER initiated BES impact through the use of NPCC's DER Impact Reporting Forms and its associated process.
6) Continue to discuss any changes required for System Restoration and Blackstart Plans, as a result of increased DER.
7) Continue to follow DER related ESA ESS safety issues and associated recommendations and share the results with NPCC stakeholders.

Planning Related Recommendations Due to Changing Resource Mix

8) Obtain DER modeling and performance data to enable Long-Term Resource, Long-Term Transmission and Operational Planning of the BES[17]
9) Clearly identify DER in the NPCC Region's Area DER and particularly PV project queues or forecasts where DER is being proposed for installation and the magnitudes relative to the existing resource base and load projections.
10) Address masking of load by DER at the distribution level to ascertain its impact on the assumptions that underpin UFLS programs

Analytics and simulation recommendations to deal with increase system complexity

11) Support interconnection wide inertia loss study efforts, to determine potential reliability impacts, as DER increasingly replaces conventional synchronous generation resources.
12) Obtain DER modelling data to be able to model, predict and examine system behavior and assess the interactions between the new resources and the existing reliability preserving systems and programs. Examples include:
    a. Under Frequency Load Shedding,
    b. Under Voltage Load Shedding,
    c. Frequency response sharing mechanisms (BAL standards).
    d. Analysis of system protection systems (both T and D) so that the parameters to set protection systems and other control systems are known so as to permit the most reliability benefits to be garnered from the new resources.

[17] What entities should be responsible for providing DER data to the Planning Coordinator for the purposes of model building?

Appendix A NPCC DER Impact Reporting Form

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

Please Complete and email this form to; npccstandard@npcc.org

Distributed Energy Resource (DER), BES Impact Reporting Form

Name		**Date**	
Email		Company	
Impact on Bulk Electric System		Area (NY, NE, State or Province etc.)	

Equipment Impacted

Equipment	**Location** (substation name, etc.)	**Impact** (Positive reliability impact? Negative reliability impact-Protection System failure, Misoperation, load affected or lost?, power quality issue?, etc)	**Duration of Impact,** (start and stop times, length of impact, ongoing? etc.)

Description of Impact on BES- What Happened or was observed?

Please describe below the details of all the impacts of the DER as it pertains to this report, such as load loss, loss of life, equipment failure or potential reliability improvement. A sequence of events showing the impact is helpful. Attach supporting information to this form if necessary.

Root Cause or additional Analysis

Please describe below the details of any investigation your company may have already done to identify causes or contributing factors to the incident. This will help NPCC route the issue properly to address it.

NPCC Review of Issue and Recommendations (i.e. refer to NERC, develop a Criteria, Guideline, Already Addressed or Identified, etc.)

NPCC Date of Resolution of Issue _____

Appendix B, NPCC Areas-Comparisons

Key Inverter based specification extracts

	ISO-NE Inverter Requirements	NG ESB 756 B, C, D	NY SIR[18]	IESO F2 Technical Requirements
Inverter Certification	yes	yes	yes	yes
Voltage and frequency trip settings for inverter based applications	yes	yes	yes	yes
Voltage Response	yes[19]	yes	yes	yes
Frequency Response	yes[20]		yes	yes
Abnormal performance capability (ride-through) requirements for inverter based applications	yes	yes		
Other grid support utility interactive inverter functions statuses	yes			
Minimum protection functions		yes	yes	
Monitoring and Control		yes	yes	yes
Reconnection to the System		yes	yes	
Distribution Protection Coordination		yes		yes
Inverter Certification		yes	yes	
Power Quality			yes	

[18] NY SIR is the New York Standardized Interconnection Requirement.

[19] The functionality is required to be present, but the default state is to have this functionality disabled unless otherwise directed by the area EPS operator

[20] The functionality is required to be present, but the default state is to have this functionality disabled unless otherwise directed by the area EPS operator

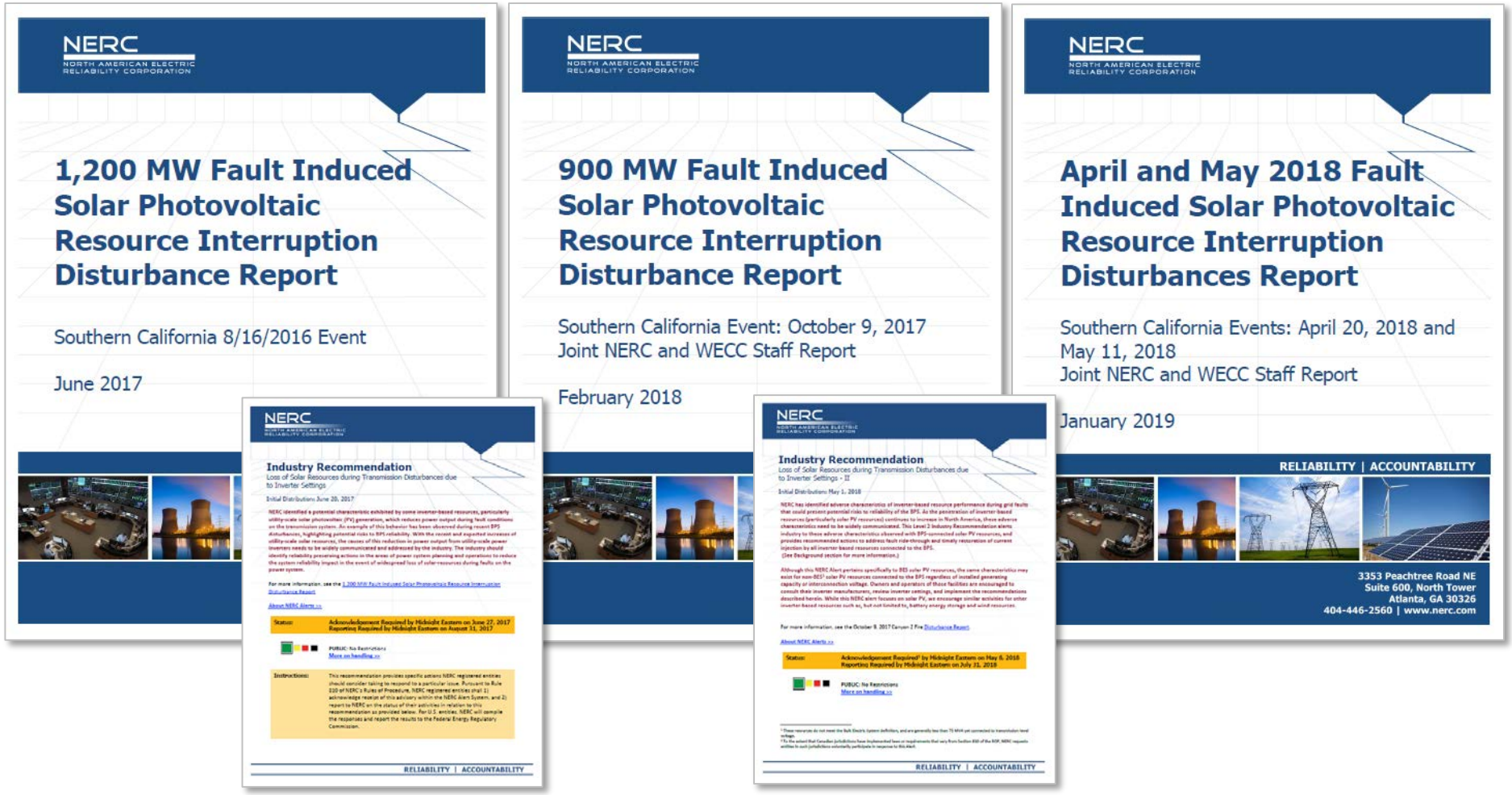
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Inverter-based Resource Activities Update

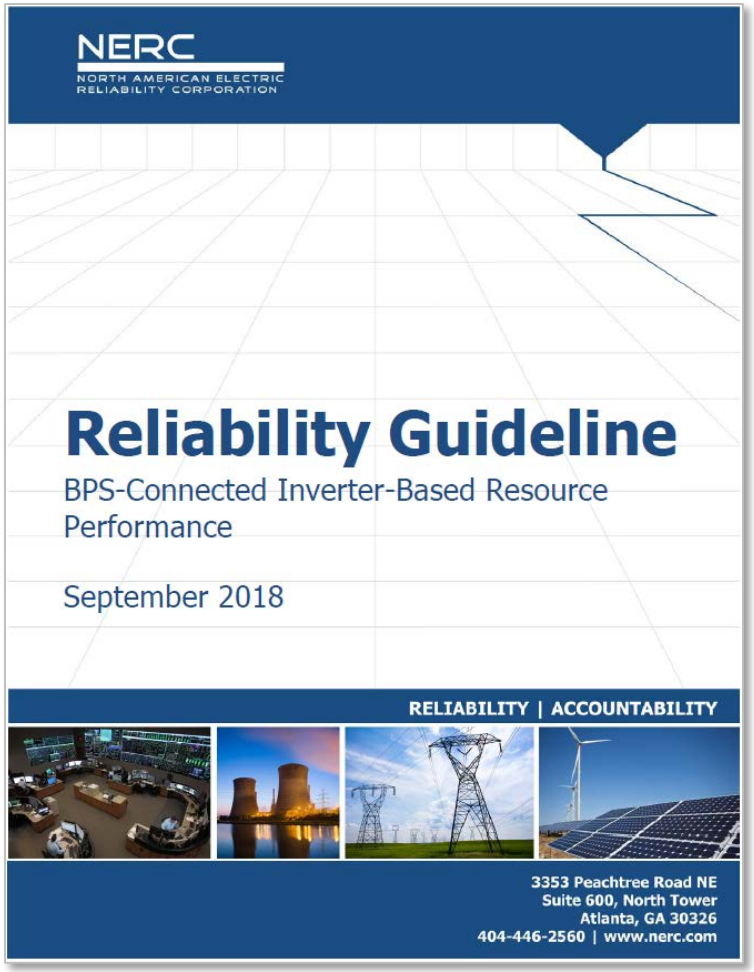
Rich Bauer
Associate Director Reliability Risk Management-Event Analysis
NPCC DER Forum
October 17, 2019

RELIABILITY | RESILIENCE | SECURITY

NERC Disturbance Reports and Alerts



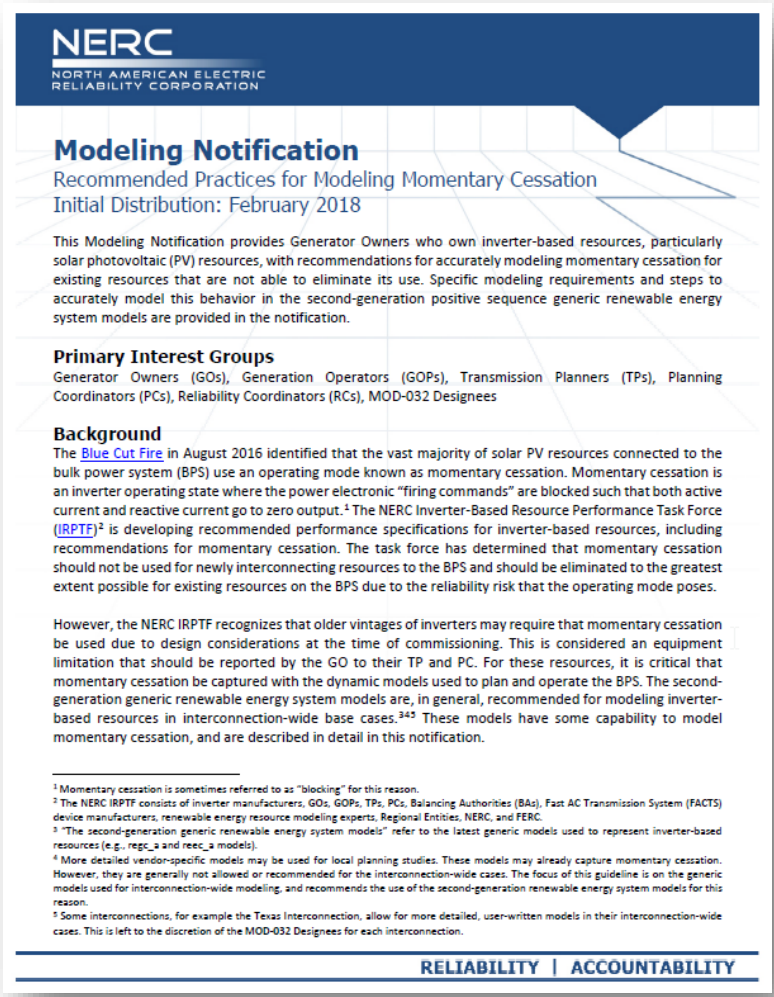
Reliability Guideline: Inverter-Based Resource Performance



- Recommended performance for BPS-connected inverter-based resources
  - Applicable to ALL – BES and non-BES resources
  - Transmission and sub-transmission
- Based on recommendations and findings from NERC disturbance reports
- Intended as cornerstone document for industry moving forward
  - Foundation for IEEE P2800
- Published September 2018

Modeling Notification: Momentary Cessation

- Existing models largely **DO NOT** accurately represent installed resource performance
  - Identified issue that must be addressed for models in planning and operations studies
  - Developed notification to help industry in modeling efforts
  - Guidance provided as part of second NERC Alert



NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Modeling Notification
Recommended Practices for Modeling Momentary Cessation
Initial Distribution: February 2018

This Modeling Notification provides Generator Owners who own inverter-based resources, particularly solar photovoltaic (PV) resources, with recommendations for accurately modeling momentary cessation for existing resources that are not able to eliminate its use. Specific modeling requirements and steps to accurately model this behavior in the second-generation positive sequence generic renewable energy system models are provided in the notification.

Primary Interest Groups
Generator Owners (GOs), Generation Operators (GOPs), Transmission Planners (TPs), Planning Coordinators (PCs), Reliability Coordinators (RCs), MOD-032 Designees

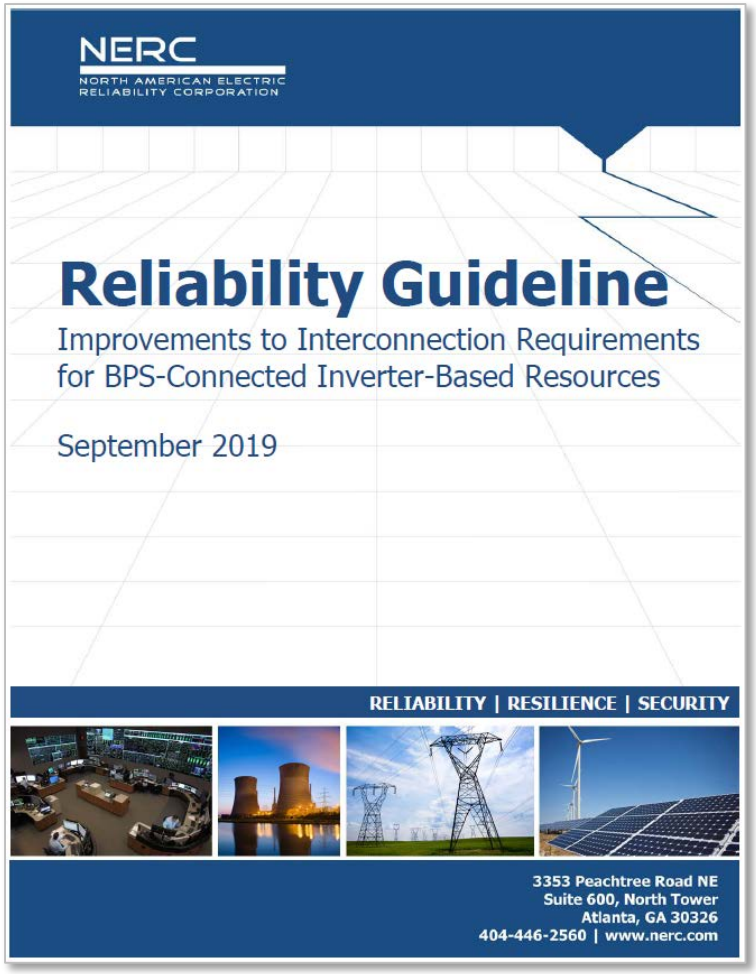
Background
The Blue Cut Fire in August 2016 identified that the vast majority of solar PV resources connected to the bulk power system (BPS) use an operating mode known as momentary cessation. Momentary cessation is an inverter operating state where the power electronic "firing commands" are blocked such that both active current and reactive current go to zero output.[1] The NERC Inverter-Based Resource Performance Task Force (IRPTF)[2] is developing recommended performance specifications for inverter-based resources, including recommendations for momentary cessation. The task force has determined that momentary cessation should not be used for newly interconnecting resources to the BPS and should be eliminated to the greatest extent possible for existing resources on the BPS due to the reliability risk that the operating mode poses.

However, the NERC IRPTF recognizes that older vintages of inverters may require that momentary cessation be used due to design considerations at the time of commissioning. This is considered an equipment limitation that should be reported by the GO to their TP and PC. For these resources, it is critical that momentary cessation be captured with the dynamic models used to plan and operate the BPS. The second-generation generic renewable energy system models are, in general, recommended for modeling inverter-based resources in interconnection-wide base cases.[3][4][5] These models have some capability to model momentary cessation, and are described in detail in this notification.

[1] Momentary cessation is sometimes referred to as "blocking" for this reason.
[2] The NERC IRPTF consists of inverter manufacturers, GOs, GOPs, TPs, PCs, Balancing Authorities (BAs), Fast AC Transmission System (FACTS) device manufacturers, renewable energy resource modeling experts, Regional Entities, NERC, and FERC.
[3] "The second-generation generic renewable energy system models" refer to the latest generic models used to represent inverter-based resources (e.g., regc_a and reec_a models).
[4] More detailed vendor-specific models may be used for local planning studies. These models may already capture momentary cessation. However, they are generally not allowed or recommended for the interconnection-wide cases. The focus of this guideline is on the generic models used for interconnection-wide modeling, and recommends the use of the second-generation renewable energy system models for this reason.
[5] Some interconnections, for example the Texas Interconnection, allow for more detailed, user-written models in their interconnection-wide cases. This is left to the discretion of the MOD-032 Designees for each interconnection.

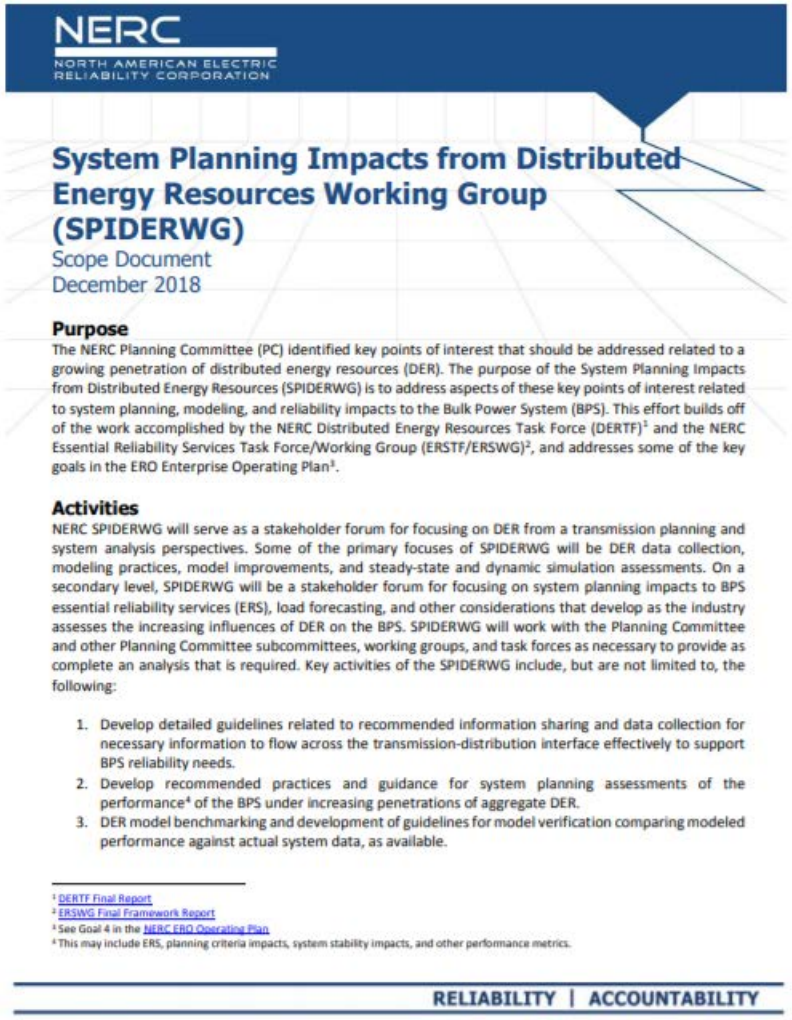
RELIABILITY | ACCOUNTABILITY

Reliability Guideline:
Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources



- Need for clarity and consistency of interconnection requirements
- Align with NERC Reliability Standards FAC-001-3 and FAC-002-2
- Based on previous IRPTF guideline and industry experience
  - Covers wide array of operational and performance issues that should be addressed
- Intended as another cornerstone document for industry moving forward
  - Coordination with IEEE P2800
- Published September 2019

SPIDERWG



NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG)

Scope Document
December 2018

Purpose

The NERC Planning Committee (PC) identified key points of interest that should be addressed related to a growing penetration of distributed energy resources (DER). The purpose of the System Planning Impacts from Distributed Energy Resources (SPIDERWG) is to address aspects of these key points of interest related to system planning, modeling, and reliability impacts to the Bulk Power System (BPS). This effort builds off of the work accomplished by the NERC Distributed Energy Resources Task Force (DERTF)[1] and the NERC Essential Reliability Services Task Force/Working Group (ERSTF/ERSWG)[2], and addresses some of the key goals in the ERO Enterprise Operating Plan[3].

Activities

NERC SPIDERWG will serve as a stakeholder forum for focusing on DER from a transmission planning and system analysis perspectives. Some of the primary focuses of SPIDERWG will be DER data collection, modeling practices, model improvements, and steady-state and dynamic simulation assessments. On a secondary level, SPIDERWG will be a stakeholder forum for focusing on system planning impacts to BPS essential reliability services (ERS), load forecasting, and other considerations that develop as the industry assesses the increasing influences of DER on the BPS. SPIDERWG will work with the Planning Committee and other Planning Committee subcommittees, working groups, and task forces as necessary to provide as complete an analysis that is required. Key activities of the SPIDERWG include, but are not limited to, the following:

1. Develop detailed guidelines related to recommended information sharing and data collection for necessary information to flow across the transmission-distribution interface effectively to support BPS reliability needs.
2. Develop recommended practices and guidance for system planning assessments of the performance[4] of the BPS under increasing penetrations of aggregate DER.
3. DER model benchmarking and development of guidelines for model verification comparing modeled performance against actual system data, as available.

[1] DERTF Final Report
[2] ERSWG Final Framework Report
[3] See Goal 4 in the NERC ERO Operating Plan
[4] This may include ERS, planning criteria impacts, system stability impacts, and other performance metrics.

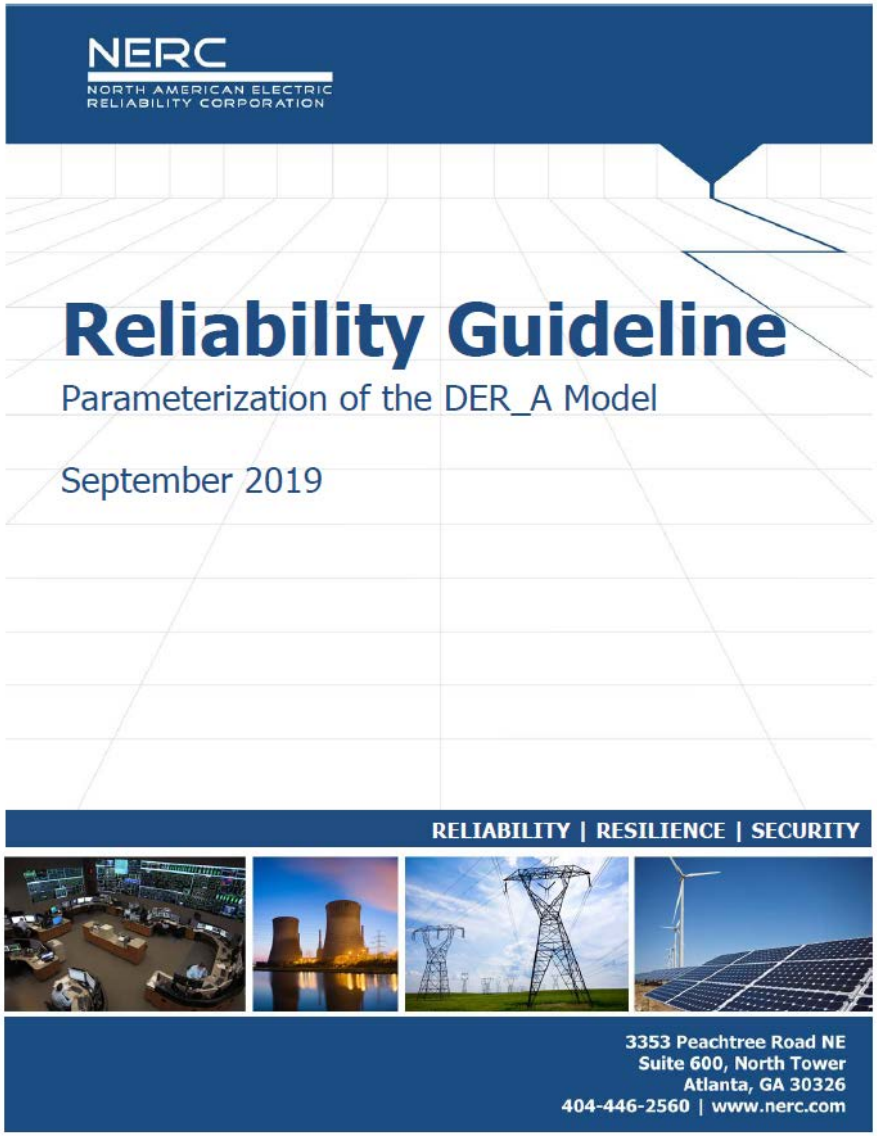
RELIABILITY | ACCOUNTABILITY

- **Purpose**: to address aspects of increasing penetration of distributed energy resources (DER) related to system planning, modeling, and reliability impacts to the bulk power system

Foundations:

- NERC Distributed Energy Resources Task Force (DERTF)
- NERC Load Modeling Task Force (LMTF

Reliability Guideline:
DER Modeling



DERTF references

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Distributed Energy Resources

Connection Modeling and Reliability Considerations

February 2017

RELIABILITY | ACCOUNTABILITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Modeling Distributed Energy Resources in Dynamic Load Models

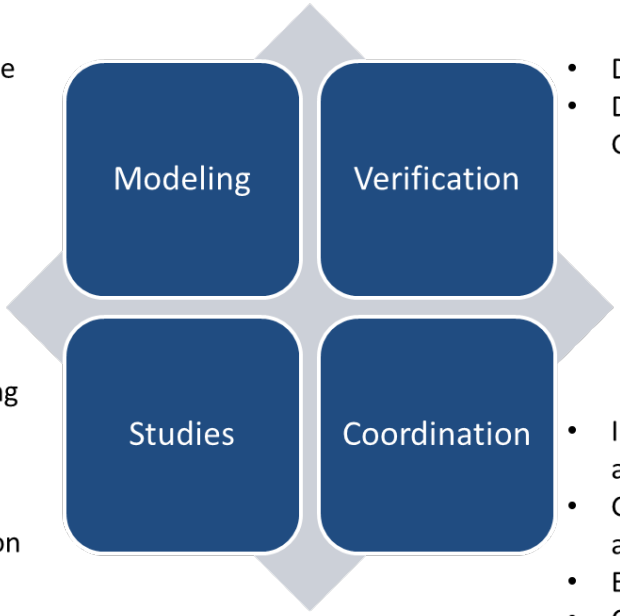
December 2016

RELIABILITY | ACCOUNTABILITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

- Encourage participation in NERC System Planning Impacts of DER Working Group (SPIDERWG)

- DER Survey
- DER_A Model Parameterization Guideline
- DER Data Collection Guideline
- Review of MOD-032-1
- Modeling Notifications



- DER Verification Guideline
- DER Forecasting Practices Guideline

- Guideline on BPS Planning Practices with DER
- White Paper: TPL-001 Standard Review
- Recommended Simulation Improvements
- UFLS/UVLS with DER Guideline

- IEEE Std. 1547-2018 Review and BPS Recommendations
- Guideline on Communicating across T-D Interface
- Education Materials
- Coordination of Terminology
- Tracking DER Growth

NERC Activities

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Summary of Activities

BPS-Connected Inverter-Based Resources and Distributed Energy Resources
September 2019

The electric power grid in North America is undergoing a significant transformation in technology, design, control, planning, and operation, and these changes are occurring more rapidly than ever before. Particularly, technological advances in "inverter-based resources"[1] are having a major impact on generation, transmission, and distribution systems. This document provides a landscape overview of this transformation with its specific changes. This document also provides some recommendations that industry, regulators, and other stakeholders may collaborate upon to ensure the continued reliability of the North American power grid.

Executive Summary

The North American Electric Reliability Corporation (NERC), as the Electric Reliability Organization (ERO), is actively supporting the reliable integration of inverter-based resources across North America by working collaboratively with key industry stakeholders. Some key takeaways from these activities include, but are not limited to, the following:

- At the distribution level, the Institute of Electronic and Electrical Engineering (IEEE) Standard (Std.) 1547-2018 is a significant advancement in ensuring improved capabilities from distributed energy resources (DERs). This standard specifies performance capabilities and addresses interconnection and interoperability. State regulators should encourage collaboration between utilities, regional reliability coordinators, industry stakeholders, and state commissions, and should support the adoption and implementation of IEEE Std. 1547-2018 to ensure consistent performance from DERs on a local, regional, and wide-area basis.
- For Bulk Electric System (BES) generation, the NERC Planning and Operating Committees and their technical working groups are actively developing consistent and clear performance requirements for all connected resources, including inverter-based resources and synchronous generation. While the intent and requirements of the standards are applicable to synchronous and inverter-based (nonsynchronous) resources, the terminology and language around these requirements need to clearly state, when applicable, the differing requirements for each technology.
- Many newly interconnecting inverter-based resources are not subject to NERC Reliability Standards nor relate to IEEE Std. 1547-2018 because these resources are connected to the Bulk Power System (BPS) but are not BES resources. In these cases, NERC is supporting Transmission Operators to

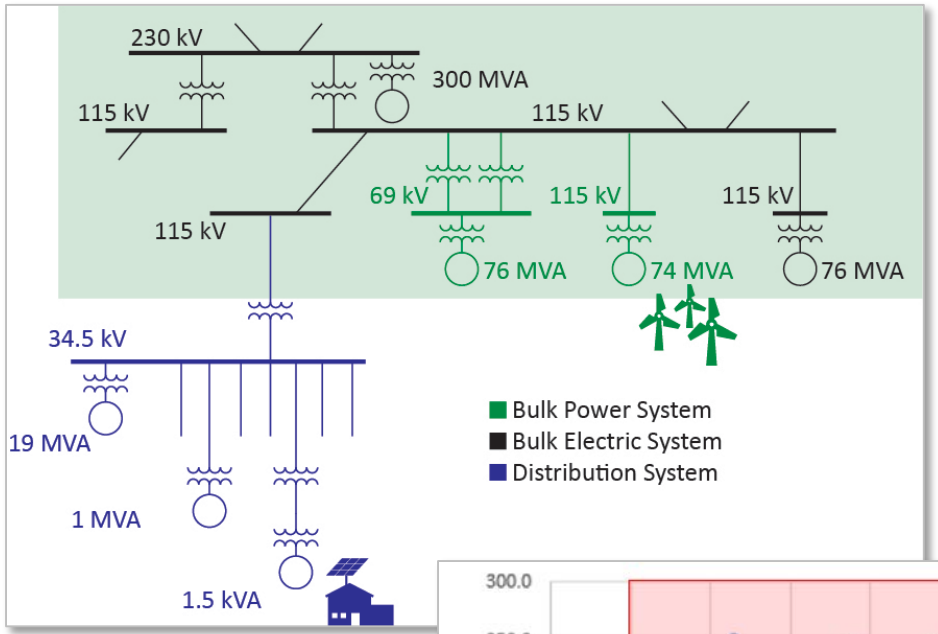
[1] In most cases, inverter-based generating resources refer to Type 3 and Type 4 wind power plants and solar photovoltaic resources. Battery energy storage is also considered an inverter-based resource. Many transmission-connected reactive devices such as STATCOMs and SVCs are also inverter-based. Similarly, HVDC circuits also interface with the ac network though converters. Inverter-based resources are being interconnected at the BPS level as well as at the distribution level, and they are differentiated accordingly throughout this paper.

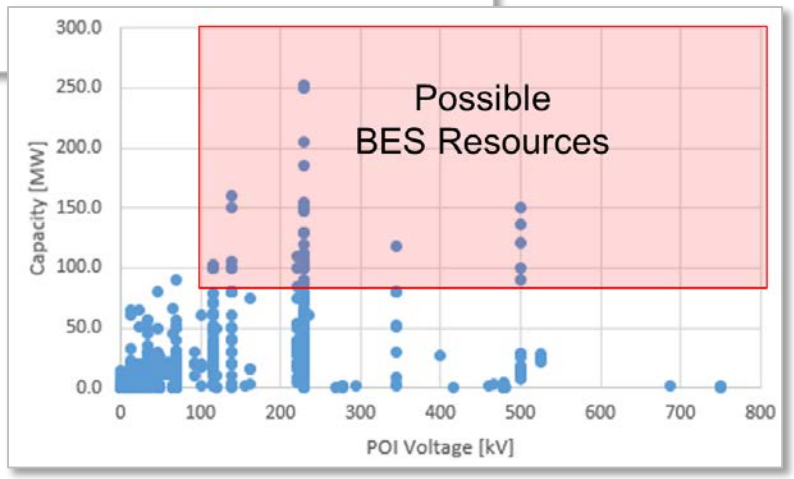
RELIABILITY | RESILIENCE | SECURITY

https://www.nerc.com/comm/PC/Documents/Summary_of_Activities_BPS-Connected_IBR_and_DER.pdf

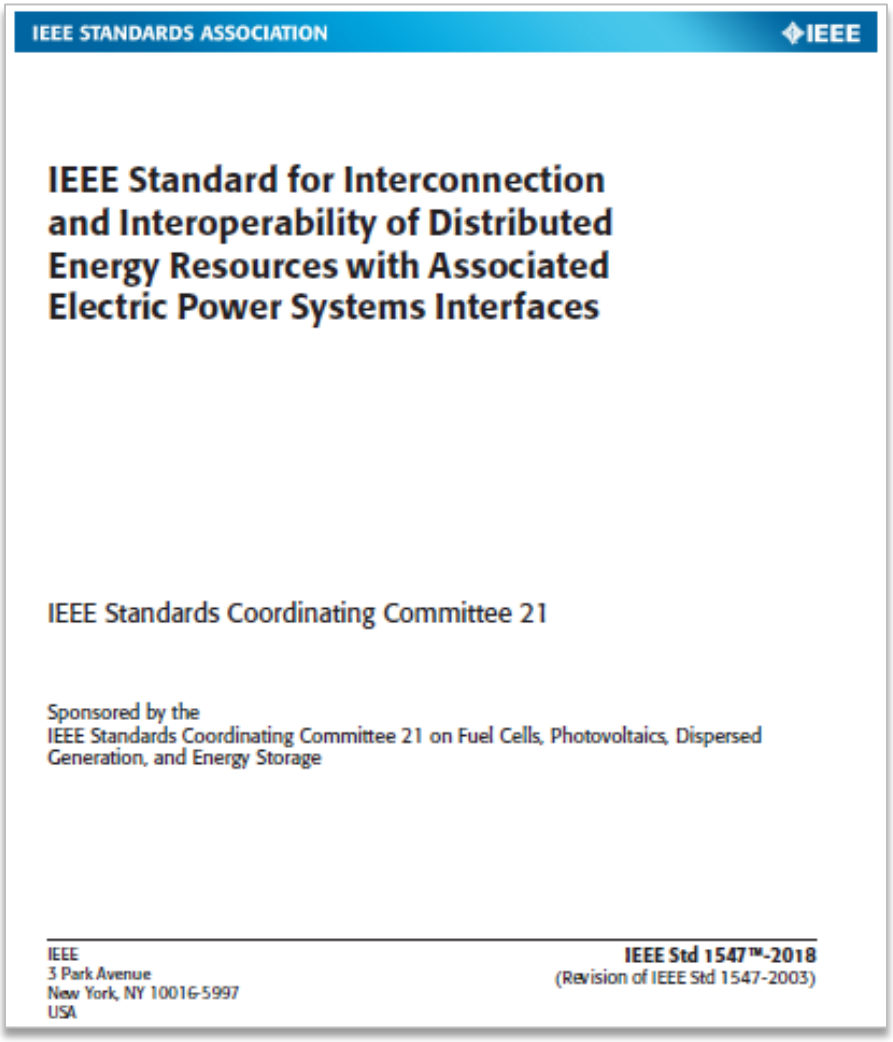
BPS vs. BES vs. Distribution System

- Coordination of activities to ensure reliability
- Development and utilization of capability, performance, and interconnection requirements
- Consistent performance across fleet to support BPS and distribution needs





IEEE Std 1547-2018


IEEE STANDARDS ASSOCIATION IEEE

IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

IEEE Standards Coordinating Committee 21

Sponsored by the
IEEE Standards Coordinating Committee 21 on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage

IEEE
3 Park Avenue
New York, NY 10016-5997
USA

IEEE Std 1547™-2018
(Revision of IEEE Std 1547-2003)

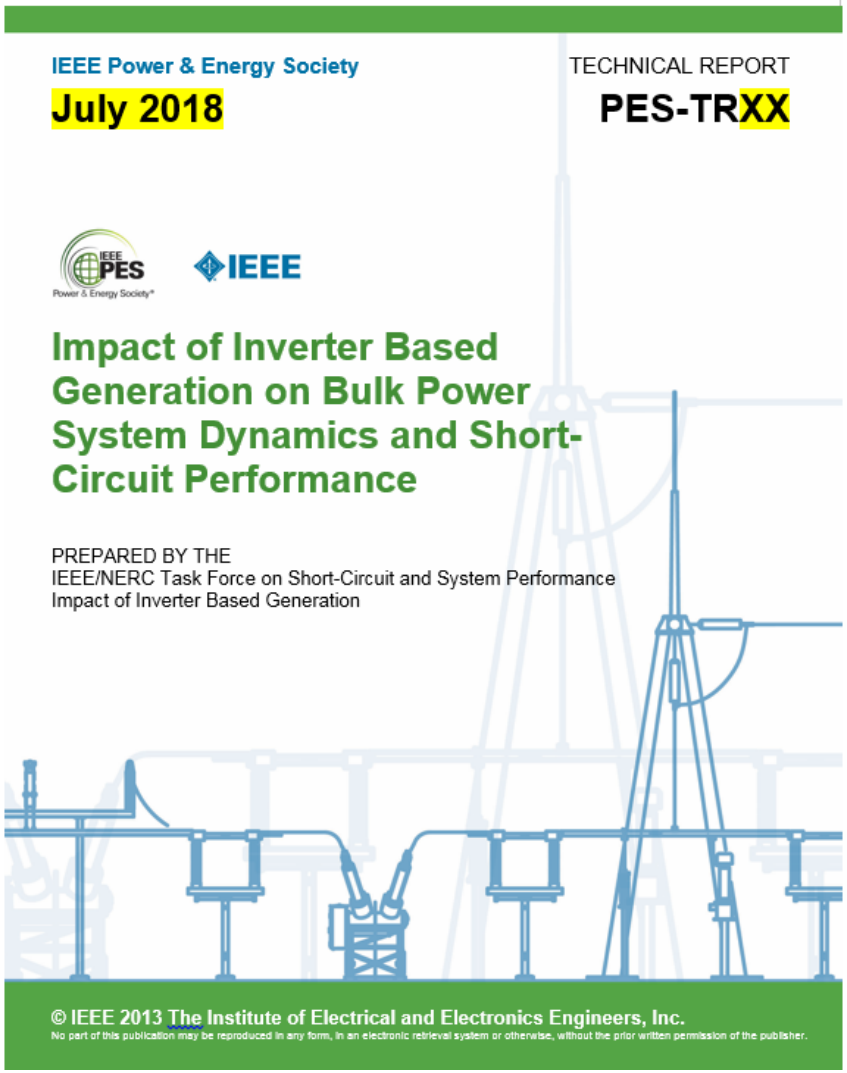
- Advanced standardization of the interconnection and interoperability of DERs connected to distribution networks.
- Addresses “performance, operation, testing, safety considerations, and maintenance of the interconnection.”
- The requirements set forth in the standard “are universally needed for interconnection of DER, including synchronous machines, induction machines, or power inverters/converters.”
- P1547.1 project developing testing and verification procedures for requirements.

IEEE Std 1547-2018 BPS Perspectives

- IEEE Std. 1547-2018 is a major improvement to previously developed standards of IEEE Std. 1547-2003 and 1547a-2014.
- Specifications relevant to BPS:
  - Entering service following disconnection due to widespread outage
  - Voltage and frequency ride through and trip settings
  - Dynamic performance during BPS disturbances (coordinated with distribution considerations)
  - Response to grid disturbances and fault events
  - Active power-frequency and reactive power-voltage performance

NERC / IEEE Joint Effort

- Issues related to large penetration of inverter-based resources
  - Controls
  - Modeling
  - Planning
  - Operations
- Protective relay issues
  - Inverter-based fault current
  - Relay element response
  - Relay scheme selection
  - Short circuit study issues



Grid Following / Grid Forming

Grid Following	Grid Forming
A grid tied inverter operates as a current source to achieve the requested power and reactive power set points.	A grid forming inverter operates as voltage source device to control the voltage and frequency.
The inverter needs to always have a grid voltage established by other generators to synchronize to and feed-in or draw power from the grid.	The inverter can work in parallel with other generators or in stand-alone mode.
In this mode, the inverter has full control over its current wave form (amplitude and angle). The inverter can achieve the requested set-points faster since it controls the current directly.	In this mode, it can also control the power and reactive power based on given set-points. Not by controlling the current but by directly adjusting the output voltage amplitude and angle (similar to synchronous generators).
In case of FRT conditions, the inverter can set its current to the requested values as per the grid codes. (magnitude and angle)	In case of FRT conditions, the inverter can only limit the current magnitude but not the angle.

Grid Following / Grid Forming

Available grid forming control concepts:

Virtual Synchronous machine (VSM)

- Mimics the swing equation of the synchronous generator - Usually does not use a PLL during normal operation - Provides inherent inertia without frequency measurements - Fault response not well studied in the literature

Power Synchronization Control (PSC)

- Does not use a PLL for normal operation but requires a back-up PLL during faults in order to limit the current - Demonstrate proven response for very weak grids - During grid faults, shifts to current control with PLL - Provides inherent inertia through the power synchronization loop

Direct power control (DPC)

- It controls the voltage and angle of the converter - very simple in its use and implementation - used widely for stand alone applications and UPS systems

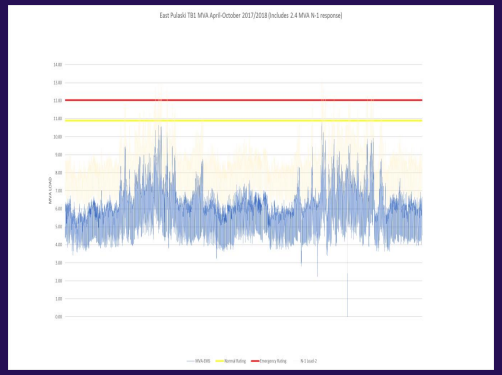
Questions

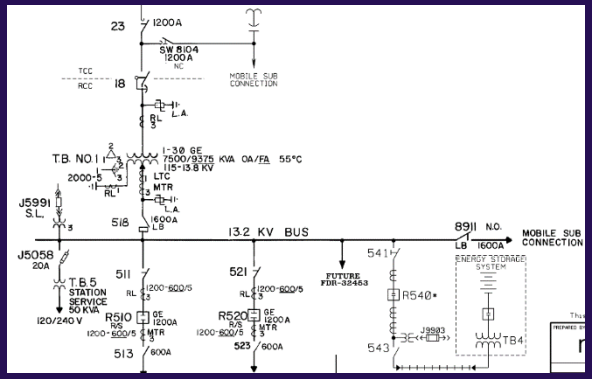
Rich Bauer
Associate Director Reliability Risk Management-Event Analysis
Office (404) 446-9738
Cell (404) 357-9843
rich.bauer@nerc.net

nationalgrid

HERE WITH YOU. HERE FOR YOU.

East Pulaski Battery Energy Storage System





October 17, 2019

Jim Dillon

Background

nationalgrid
HERE WITH YOU. HERE FOR YOU.

The East Pulaski 115-13.2 kV station in Pulaski, NY serves primarily rural customers in Upstate New York near the Salmon River and Lake Ontario. During the summer, station bank overloading could occur during peak hours and when it is relied on to avoid extended customer outages in the surrounding area. Load relief through adjacent feeder ties was utilized to reduce station loading below operating limits for system normal periods.

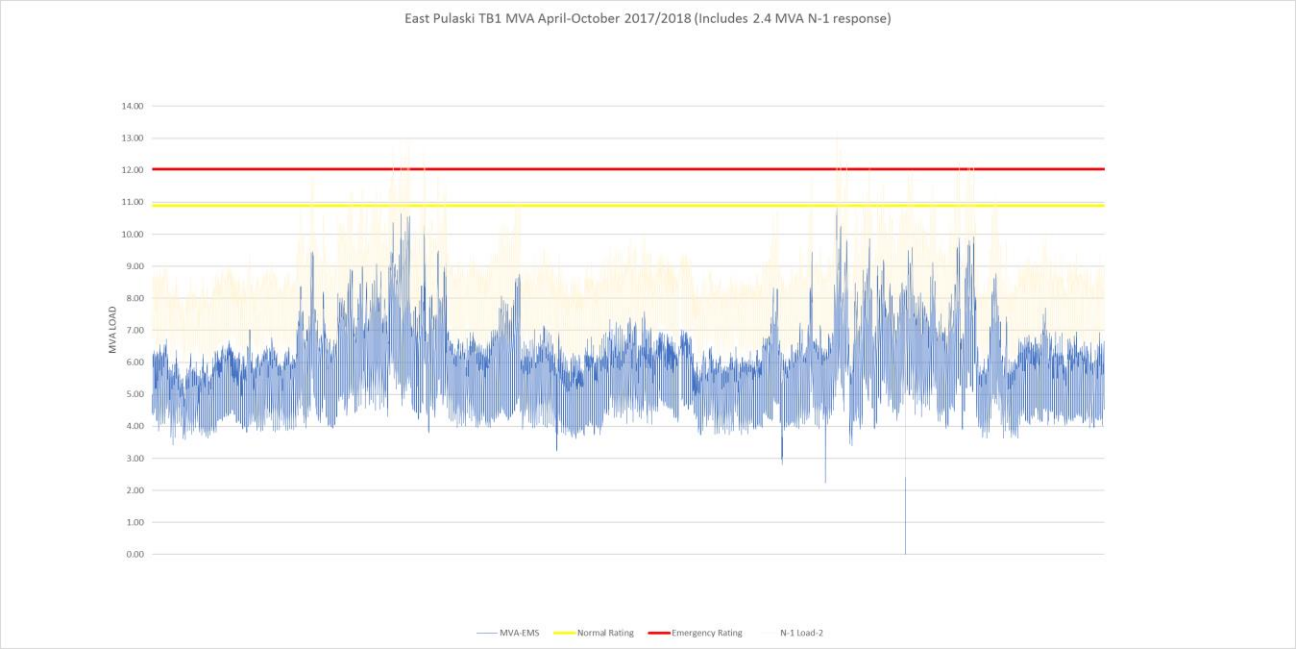
A capital replacement project to increase the station capacity was in the early development stages when our regulators announced their Order on Distributed System Implementation Plan for each utility in New York to deploy two energy storage projects.

After careful consideration of projects in the budget, this site was chosen as one of the pilot sites in National Grid's service territory.

Needs Case

nationalgrid
HERE WITH YOU. HERE FOR YOU.

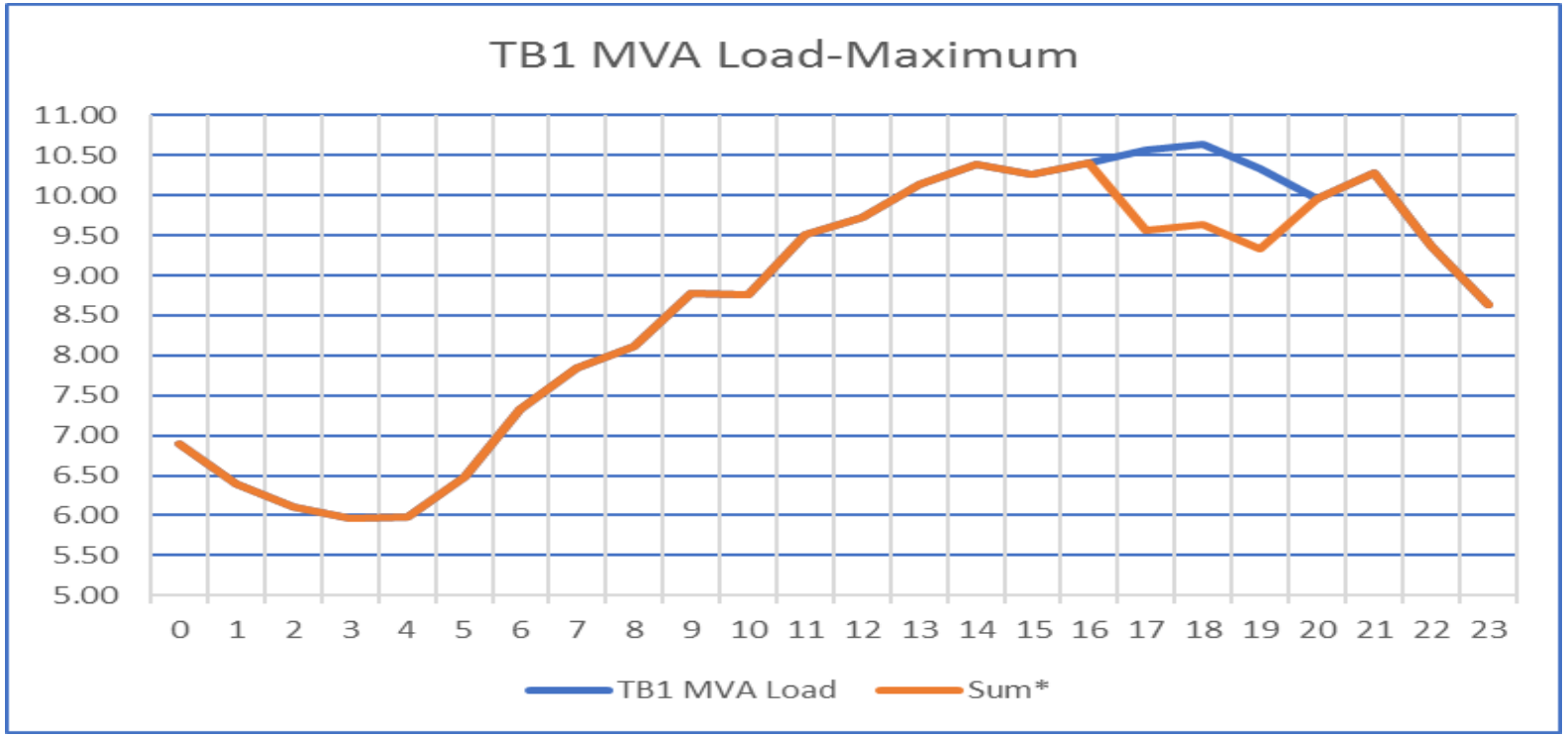
The circumstances of the overloading conditions are limited to a narrow time-frame (2-4 hours) during the summer load period (June-September).



Needs Case

nationalgrid
HERE WITH YOU. HERE FOR YOU.

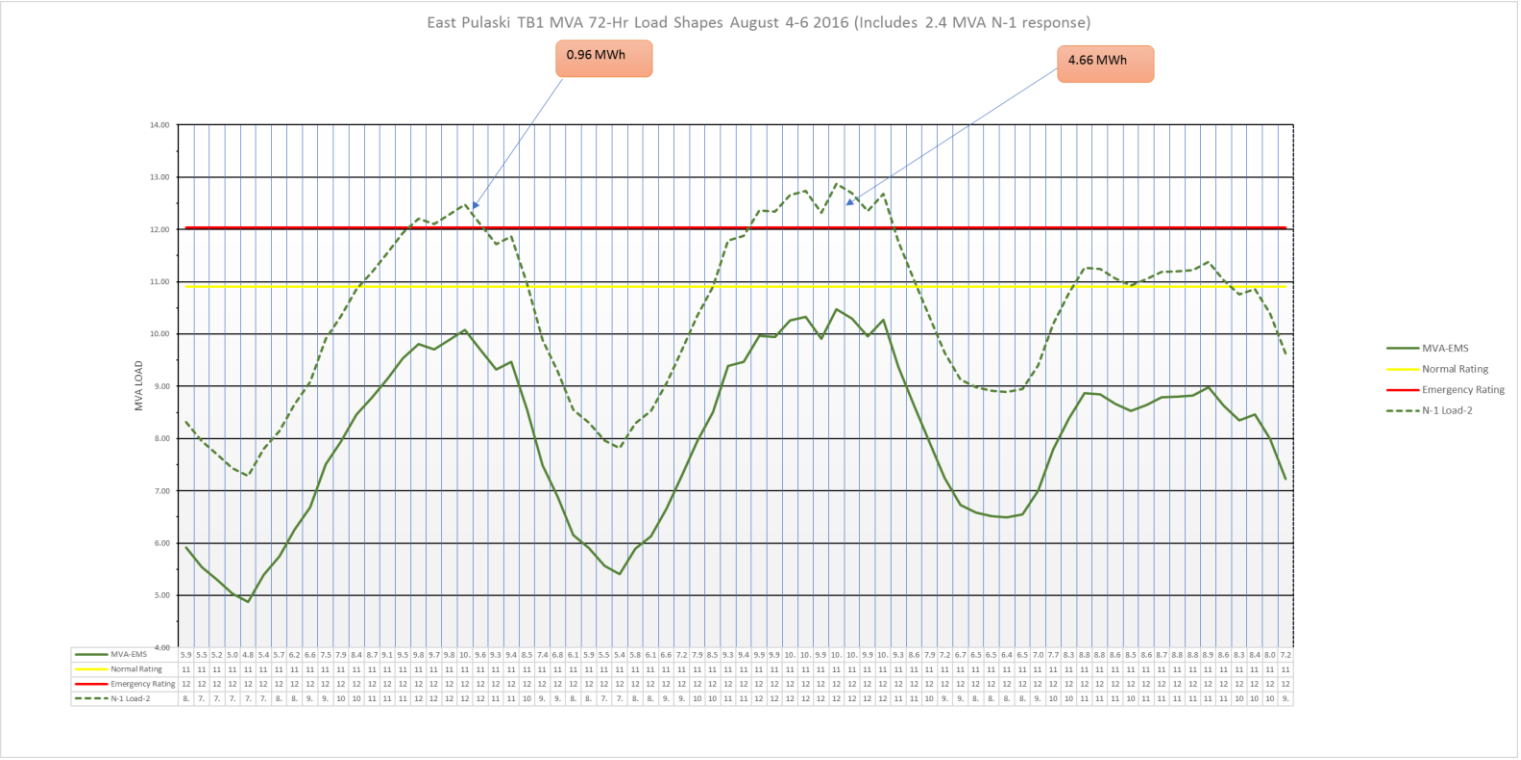
Determining the battery size and capacity- Peak seasonal hourly values 2016-2017



Needs Case

nationalgrid
HERE WITH YOU. HERE FOR YOU.

Contingent Planning for Battery Operation



Needs Case

nationalgrid
HERE WITH YOU. HERE FOR YOU.

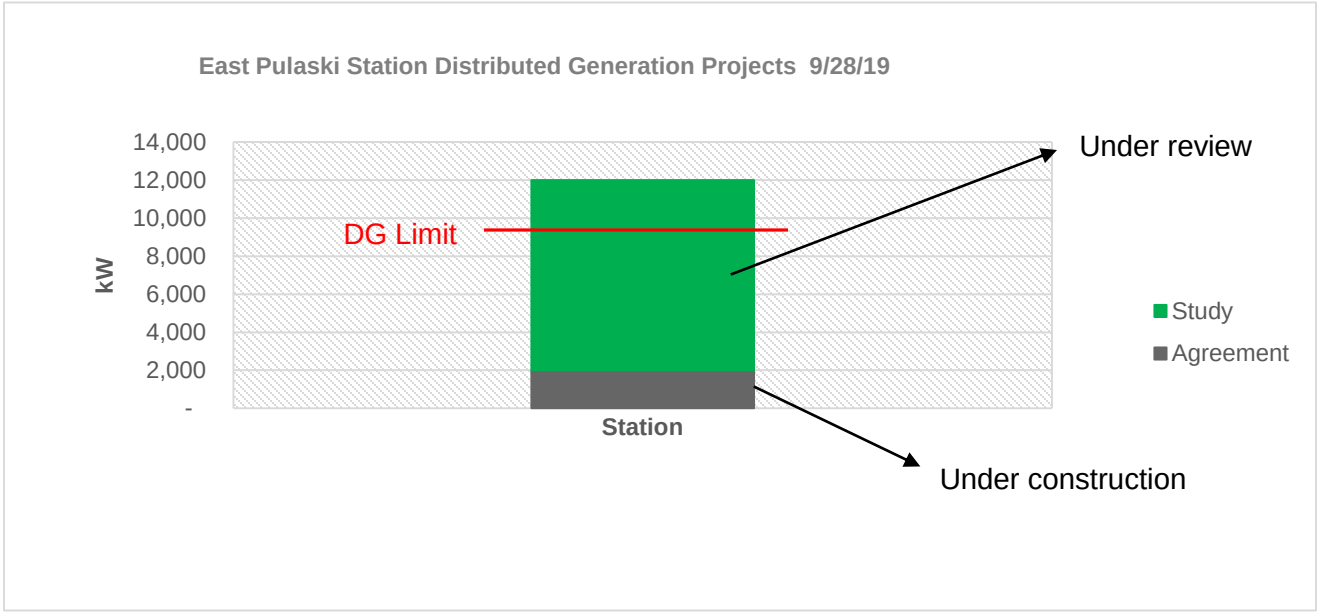
BESS Capacity Request

- 2.0 MW/3.5 MWh
- Planning Considerations-
  - Assumed 120 minutes for emergency switching duration.
  - Future load projections (8760-hr 10 year forecasts) flat
  - Rural area with DG Solar opportunities

Needs Case

nationalgrid
HERE WITH YOU. HERE FOR YOU.

The territory served by the East Pulaski station is very rural with opportunity for the development of large solar farms (2-5 MW/site).



Challenges

nationalgrid
HERE WITH YOU. HERE FOR YOU.

- Developing Familiarity with technology
  - Battery and control system capabilities and limitations
  - SCADA point definitions and selection
  - Ease of use-“Operator friendly”
  - Maintenance of more complex battery system

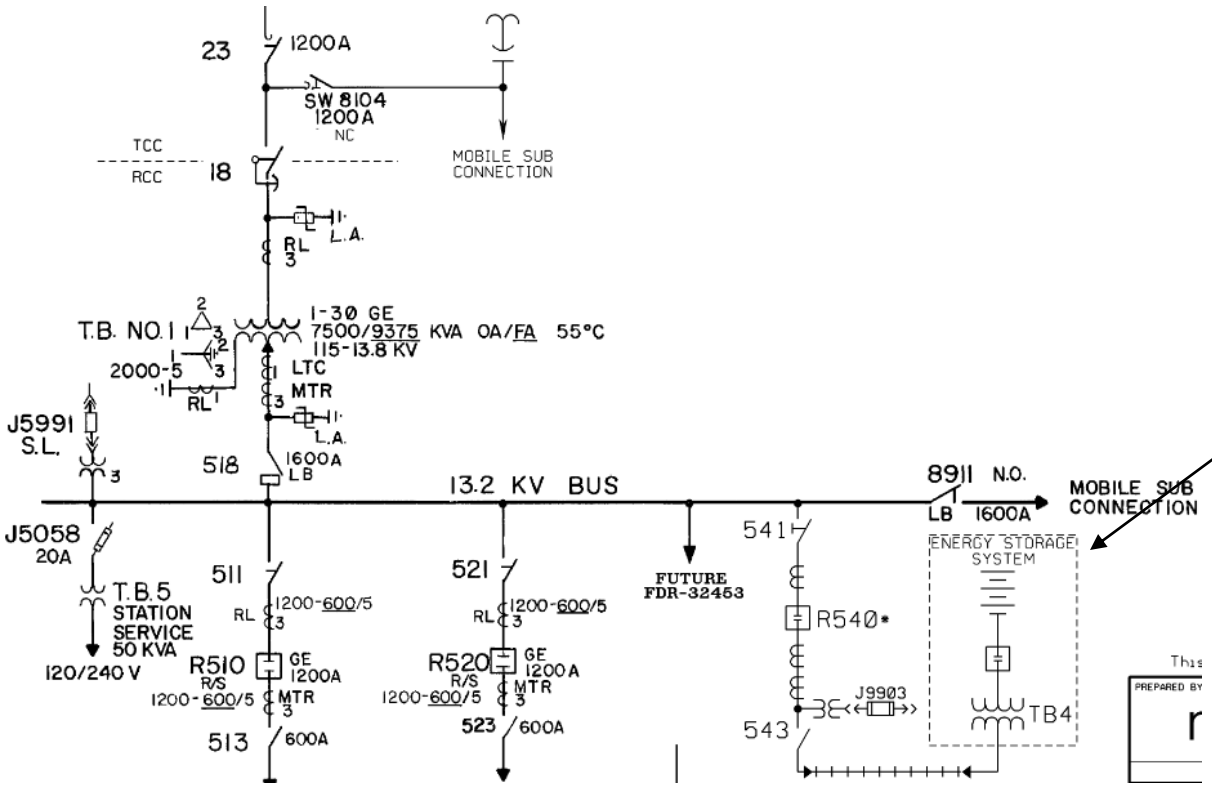
Challenges

nationalgrid
HERE WITH YOU. HERE FOR YOU.

- Defining operating parameters to meet needs case
  - Charge/Discharge characteristics
    - Periods and durations
    - Fixed rate or threshold levels
    - Forecasting – Day/week ahead on more granular level

Final Product

nationalgrid
HERE WITH YOU. HERE FOR YOU.



2.0 MW/3.8 MWh

Open Items

nationalgrid
HERE WITH YOU. HERE FOR YOU.

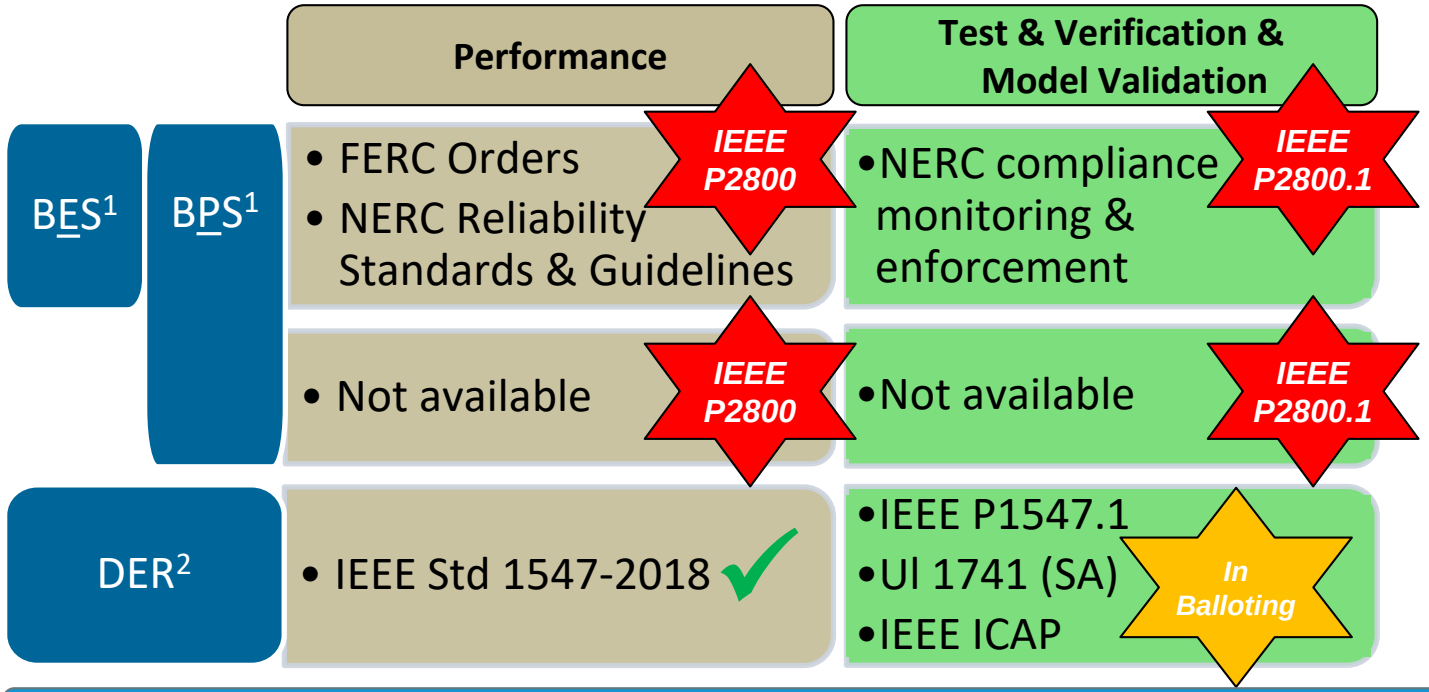
- Training for take over of O & M and operating activities
- Market Participation
  - Ensuring capacity available for primary need case
  - Evolving Market Development

Implementation of the Revised IEEE Standard 1547

Presentation to NPCC Regional Standards Committee

David Forrest

Overview of Applicable Interconnection Standards – *IEEE 1547 not applicable to BPS resources!*



[1] NERC definition of Bulk Electric System: ≥100 kV with gross individual / aggregate nameplate rating greater than 20 MVA / 75 MVA

[2] May include meshed sub-transmission

[3] DER connected at typical (radial) primary and secondary voltage levels

IEEE standards are voluntary industry standards and must be adopted by the appropriate authority to become mandatory.

BACKGROUND

STATUS OF IEEE 1547 AND UL 1741

IEEE 1547

- The approved revision to 1547 underwent final editing at IEEE and was published in early April 2018
- Before DER can be certified as meeting the revised 1547, the testing standard 1547.1 must be revised
- 1547.1 was balloted and received over a 75% approval
- Over 1500 comments were received and addressed and 1547.1 has been recirculated with comments due by October 22
- Depending on what comments are received, 1547.1 will be deemed complete or recirculated
- Once 1547.1 is approved, UL 1741 will need to be updated to agree with the revised 1547.1
- Once UL 1741 is updated and approved, it will take a year or longer for all inverter manufacturers to have their inverters tested and certified
- Thus it will be late 2020 or later before utilities will able require use of IEEE 1547-2018

IEEE 1547

- Based on experience implementing IEEE 1547 in MISO, New England and PJM, EPRI has spearheaded an IEEE effort to amend IEEE 1547-2018
- The amendment will allow utilization of Category III inverters and allow under voltage trip settings similar to 1547-2003 settings that satisfy distribution utility concerns
- The amendment was approved by the working group and will be balloted in the near future
- I encourage people to join the ballot group and support this amendment

IEEE P1547a Project Authorization

Available online:
https://development.standards.ieee.org/P1139500033/par

Title: Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces – Amendment to IEEE Std 1547-2018 to provide more flexibility for adoption of abnormal operating performance Category III

Scope: This amendment revises the ranges of allowable trip clearing time settings in Table 13 for DERs in abnormal operating performance category III. No changes are expected for the default trip settings in any of the tables and abnormal operating performance categories. Informative figure H.9 will be updated. No other changes of the language in IEEE Std 1547-2018 shall be part of this amendment.

➢ ***Approved by the IEEE SASB on September 5, 2019***

P1547a Proposal: Partial harmonization of ranges of Category III with Category I and II (lower value only)

1. Revise lower value of Category III range of allowable settings for UV1 and UV2 clearing time.
2. Leave all Category III default settings as is.
3. Revise informative figure H.9 accordingly.

Table 13—DER response (shall trip) to abnormal voltages for DER of abnormal operating performance Category III (see Figure H.9)

Shall trip—Category III				
Shall trip function	Default settings[a]		Ranges of allowable settings[b]	
	Voltage (p.u. of nominal voltage)	Clearing time (s)	Voltage (p.u. of nominal voltage)	Clearing time (s)
OV2	1.20	0.16	fixed at 1.20	~~fixed at 0.16~~
OV1	1.10	13.0	1.10–1.20	1.0–13.0
UV1	0.88	21.0	0.0–0.88	~~21.0~~ **2.0**–50.0
UV2	0.50	2.0	0.0–0.50	~~2.0~~ **0.16**–21.0

[a]The Area EPS operator may specify other voltage and *clearing time* trip settings within the *range of allowable settings*, e,g., to consider Area EPS protection coordination.

[b]Nominal system voltages stated in ANSI C84.1, Table 1 or as otherwise defined by the Area EPS operator. The *ranges of allowable settings* do not mandate a requirement for the DER to ride through this magnitude and duration of abnormal voltage condition. The Area EPS operator may specify the voltage thresholds and maximum *clearing times* within the *ranges of allowable settings*; settings outside of these ranges shall only be allowed as necessary for DER equipment protection and shall not conflict with the voltage disturbance ride-through requirements specified in 6.4.2. For the overvoltage (OV) and undervoltage (UV) trip functions *clearing time* ranges and for the OV trip functions voltage ranges, the lower value is a limiting requirement (the setting shall not be set to lower values) and the upper value is a minimum requirement (the setting may be set above this value). For the UV trip functions voltage ranges, the upper value is a limiting requirement (the setting shall not be set to greater values) and the lower value is a minimum requirement (the setting may be set to lower values).

Source: EPRI

Timeline for rollout of 1547 amendment,1547.1 and UL 1741

Dates	Activities	Status
April 2018	**Milestone:** IEEE 1547-2018 published: New DER grid interconnection requirements established. In parallel: IEEE 1547.1 update in progress. (New test procedures to verify conformance to 1547-2018)	Complete
February 26-27, 2019	IEEE P1547.1 WG meeting – Draft 9.3 approved by Working Group	Complete
March 2019	Final pre-ballot edits to P1547.1	Complete
April 2019	**Milestone:** Final WG vote to send P1547.1 Draft 9.4 to IEEE-SA	Complete
April 2019	P1547.1 D9.4 sent to IEEE-SA for ballot invitation and MEC review	Complete
Q2-Q3 2019	IEEE-SA balloting and ballot resolution of P1547.1 (iterative)	In progress
Q4 2019	UL 1741 begin revision draft to incorporate new 1547.1 and 1547	
Q4 2019	**Milestone:** IEEE-SA ballot approval of P1547.1	
January 2020	IEEE RevCom review of P1547.1 In parallel: Finalize UL 1741 ballot document to incorporate new 1547.1.	
Q1/Q2 2020	**Milestone:** 1547.1 finalization and publication	
Q1/Q2 2020	UL Standards Technical Panel review and ballot updated UL 1741	
Q1/Q2 2020	**Approval and Publication of Amendment to IEEE Std 1547-2018**	
Q2/Q3 2020	**Milestone:** UL 1741 update published	
Q3 2020 – Q4 2021	Inverter manufacturers update and recertify products to UL 1741	
Q4 2020 – Q4 2021	UL 1741 / 1547-2018 compliant inverters expected to be available on market	

Interim Solution-Timeline

- The following implementation schedule was implemented in Massachusetts
  - All inverter-based solar PV projects 100kW or less with applications submitted on or after June 1, 2018 are subject to the ISO-NE Source Requirement Document
  - All inverter-based solar PV projects greater than 100kW with applications submitted on or after March 1, 2018 are subject to the ISO-NE Source Requirement Document
  - Inverter-based solar PV projects with applications submitted prior to the above dates were encouraged to comply with the ISO-NE Source Requirement Document with the approval of the interconnecting utility

EFFORTS TO IMPLEMENT IEEE 1547-2018

Example Adoption of IEEE Std 1547-2018

ISO New England

- Coordination between ISO-NE and the MA's utilities in the Massachusetts Technical Standards Review Group
- Reference to UL 1741 SA as a stopgap to verify DER ride-through capability in the interim
  - Harmonization of voltage & frequency trip settings with IEEE Std 1547-2018 ranges of allowable settings
- Full adoption of IEEE Std 1547-2018 under way since early 2019

PJM Interconnection

- Two ad-hoc stakeholder workshops in 2018 for DER ride-through categories and trip settings (PJM website)
- Initiation of formal stakeholder proceedings in 2019 (PJM website)
- Published a draft reliability guideline for voluntary DER ride-through in August 2019 (PJM Website)

Minnesota Public Utilities Commission

- Phase 1 (2017): Interconnection Process, Applications, Agreements
- Phase 2 (2018): Technical Requirements consistent with IEEE Std 1547-2018 (MN PUC website)
- Coordination with regional reliability coordinator, e.g., MISO (MISO's IEEE 1547 website)

Source: EPRI

Example Adoption of IEEE Std 1547-2018

- As reported at the May 16, 2019 meeting, in New England, inverters meeting UL 1741 SA were required starting in 2018
- ISO-NE is working with the MA TSRG on the implementation of 1547-2018
  - Over 50 responsibilities have been identified in IEEE 1547-2018
  - Area EPS Operator has a role in over 40 of these responsibilities, some of which require input from the Regional Reliability Coordinator and the Responsible Transmission Planners
  - A subcommittee of the MA TSRG will meet over the next year to make the decisions required for the implementation of 1547-2018

Example Adoption of IEEE Std 1547-2018

- After a few meetings on the implementation of 1547-2018 a few additional issues have surfaced
  - Utilities expressed the need for early identification required updates to state regulations to allow time for those regulations to be revised
  - Utilities expressed concerns about the interaction between frequency regulation (frequency droop) and anti-islanding protection for existing and new DER – not everyone is aware of latest research findings
  - Transmission Operators expressed the need for considering 1547-2018 “enter service” settings in black start studies
  - Transmission planners express the need to track the location of the various editions/legacies of DER (1547-2003, ISO-NE SRD & 1547-2018)
  - Developers expressed the need to choose communication protocols to allow lead time for the manufacturers

REFERENCES

Sponsor Website for IEEE Std 1547-2018

http://sites.ieee.org/sagroups-scc21/standards/1547rev/

- General
- Scope
- Purpose
- Leadership Team
- **Sources**
  - ✓ **discounted copies**
- **SCC21-Reviewed Slide Decks Available for Interested Lecturers**
- **Further Reading**
- **Webinars**

Please submit further reading suggestions via the web form!

Publicly Available EPRI Resources on IEEE Std 1547-2018

EPRI Training Modules (EPRI-U)	Webinar	Quiz
1. *Overview on IEEE Std 1547-2018*, Dec. 2018	Public (3002014545)	Quiz 1
2. *DER Ride-through Performance Categories and Trip Settings*, Dec. 2018	Public (3002014546)	Quiz 2
3. *T+D Coordination for DER Ride-Through and Trip Requirements*, Dec. 2018	Public (3002014547)	N/A

https://www.epri.com/#/epri-u?lang=en-US

EPRI White Papers	Availability
5. *Fact Sheet*, May 2017	Public (3002011346)
6. *Minimum Requirements for DERs Ride-Through*, May 2015	Public (3002006203)
7. *Communications Interface and Interoperability*, Jul. 2017	Public (3002011591)
8. *Power Quality Considerations for DERs*, Dec. 2017	Public (3002010282)

https://www.epri.com/#/?lang=en-US

Selected References for Further Reading

IREC (2019): Making the Grid Smarter. Primer on Adopting the New IEEE 1547-2018 Standard for Distributed Energy Resources. Interstate Renewable Energy Council (IREC). Available online at https://irecusa.org/publications/making-the-grid-smarter-state-primer-on-adopting-the-new-ieee-standard-1547-2018-for-distributed-energy-resources/ .

NRECA (2019): Guide to IEEE 1547-2018 Standard for DER Interconnections. National Rural Electric Cooperative Association (NRECA). Available online at https://www.cooperative.com/topics/transmission-distribution/Pages/NRECA-Guide-to-IEEE-1547-2018-Standard-for-DER-Interconnections.aspx .

EPRI (2019): Transmission and Distribution Operations and Planning Coordination. TSO/DSO and Tx/Dx Planning Interaction, Processes, and Data Exchange. 3002016712. Palo Alto, CA. Available online at https://www.epri.com/#/pages/product/000000003002016712/ .

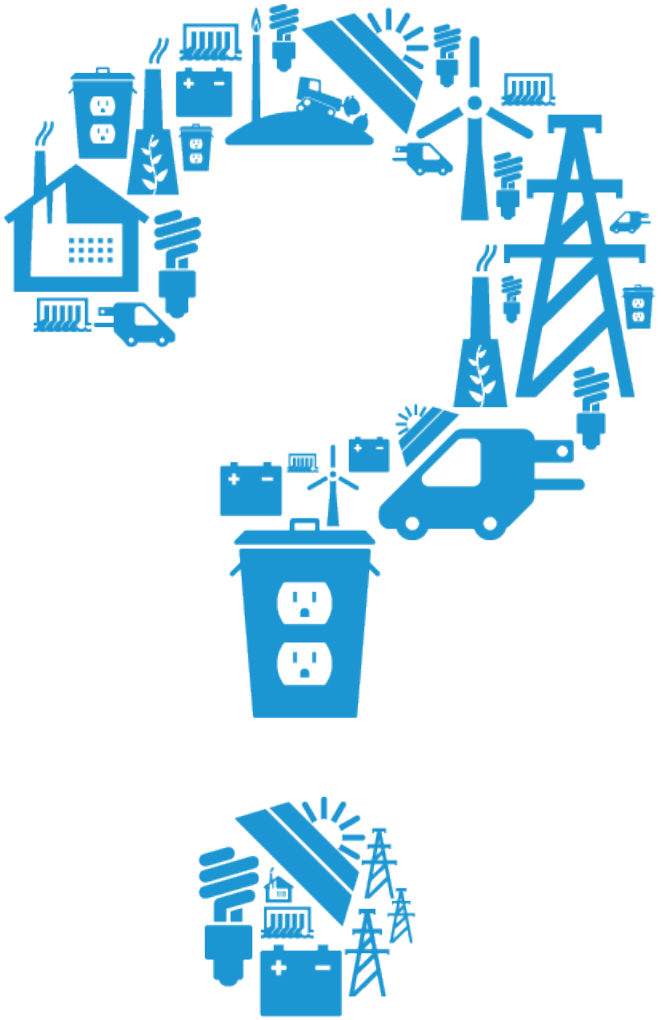
NRECA (2018): The National Rural Electric Cooperative Association (NRECA) published four articles in January 2018 that focus on the IEEE 1547's impact on the electric grid and electric cooperatives: https://www.cooperative.com/topics/operations/pages/ieee-standard-1547.aspx

2018 WIRAB Webinar: Implementation of IEEE 1547 Standard – Interconnection of DERs and Utility Electric Power Systems. August 21, 2018. Available online at https://westernenergyboard.org/2018/06/wirab-webinar-road-map-to-unplug-benefits-of-advanced-der-capability-functions/

North American Electric Reliability Corporation (NERC) (2013): Performance of Distributed Energy Resources During and After System Disturbance. Voltage and Frequency Ride-Through Requirements. North American Electric Reliability Corporation (NERC). Available online at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/IVGTF17_PC_FinalDraft_December_clean.pdf

North American Electric Reliability Corporation (NERC) (2017): Distributed Energy Resources. Connection, Modeling, and Reliability Considerations. North American Electric Reliability Corporation (NERC). Available online at http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf .

Questions



IEEE P1547a

Draft Amendment to IEEE Std 1547™,
IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces,
to provide more flexibility for adoption of abnormal operating performance Category III

How To Join The Ballot Group?
Deadline: October 23!

Chair – David Narang
Vice-Chairs – John Berdner, Jens C. Boemer, Babak Enayati, Bob Fox, Mark Siira
Secretary – Charlie Vartanian

Where We Are In The Process

✓ Sep 19, 2019	1st WG Meeting *(minutes are available on iMeet here)*
✓ **Sep 23 - Oct 23, 2019**	**Formation of ballot group / ballot invitation**
✓ Sep 26, 2019	2nd WG meeting and approval of Initial Ballot Draft by conference Call *(minutes are available on iMeet here)*
■ Oct 3, 2019	3rd WG meeting (*to be rescheduled*, if needed)
■ **Oct 4 - Oct 17, 2019**	**Mandatory Editorial Coordination (MEC) – *ongoing***
■ Oct 18 - Oct 25, 2019	Approval of Entering Initial Ballot at SCC21 meeting[1]
■ **Oct 28 - Nov 29, 2019**	**Initial Ballot**
■ Dec 2 -Dec 13, 2019	Ballot resolution (CRT within WG)
■ Dec 16-27, 2019	Recirculation (as needed)
■ Jan 24, 2020	Approval by SCC21[1]
■ **Jan 24, 2020**	**Submission to RevCom**
■ Mar 6-7, 2020	Approval by RevCom and SASB
■ **May 2020**	**Publication of the Amendment**

Notes:

- *Red dates are tentative*
- *Grey dates are tentative.*

[1] electronic vote opens one week before the meeting

Ballot Pool Formation Opened Sep 23

Duration: Sep 23 - Oct 23, 2019

Roster

- Power & Energy Society – Transmission & Distribution – Distribution Resources Integration Working Group (PE/T&D/DRI)
- SCC21 – 1547/1 (SASB/SCC21/1547.1 testing WG)
- SCC21 – DR Interconnection Application Guide Procedures Working Group (SASB/SCC21/1547.2WG)
- 1547 Revision Working Group (SASB/SCC21/1547_revwg)
- 1547WG for interconnecting DR with EPS's (SASB/SCC21/P1547WG)

Extended Roster (per forwarding to Committee Chairs)

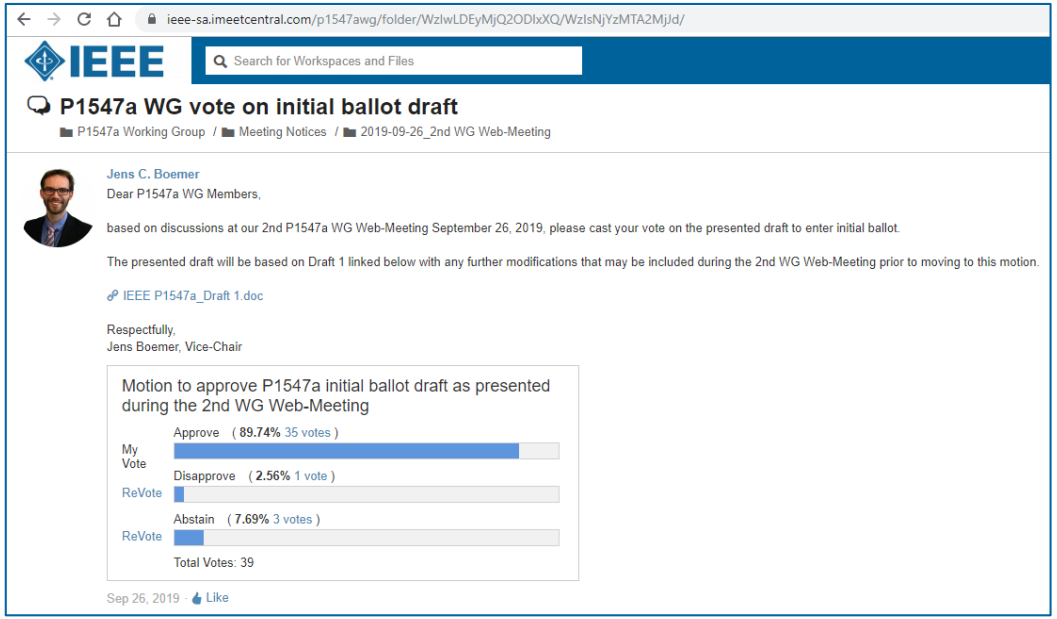
- Wind and Solar Plant Interconnection Performance Working Group (WSPI-P) (PE/EDPG/WSPPID/WSPI/WSPI-P)
- Generator SC - Renewable Energy Machines and Systems - WG#9 (PE/EM/GEN – WG9)
- Generator SC - Coordination of C50s and IEC - WG#8 (PE/EM/GEN - WG8)
- Power System Relaying and Control (PE/PSRCC)
- IEEE Guide for Application of Neutral Grounding in Electrical Utility Systems, Part VI--Systems Supplied by Current-Regulated Sources (PE/SPDHV/HV3.5.7/C62.92.6)

WG Approved Initial Ballot Draft on Sep 26

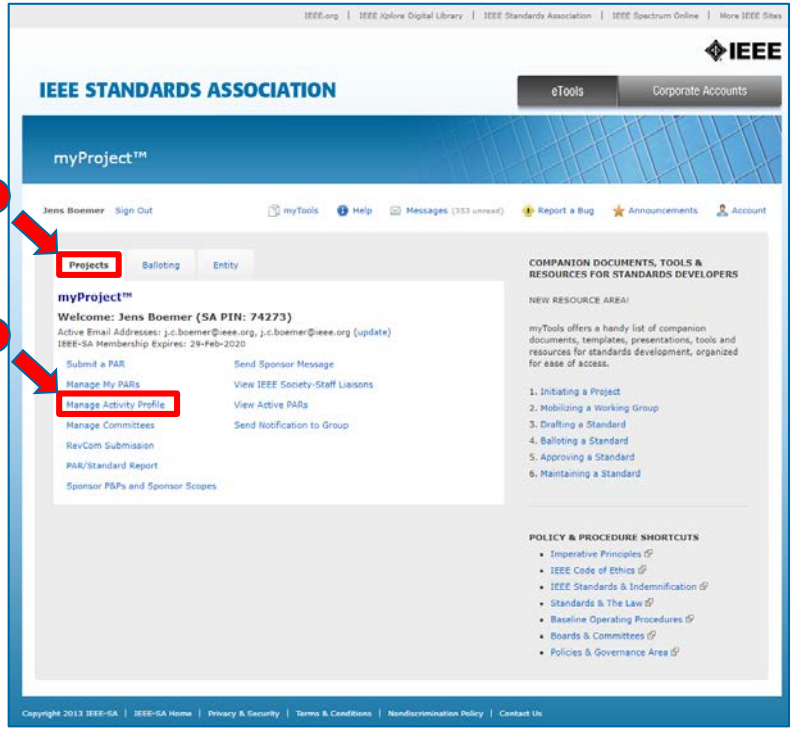
- Initial Ballot Draft available on iMeet: https://ieee-sa.imeetcentral.com/p/aQAAAAAD9G-W
- A motion to approve the draft was confirmed on the call by roll call:

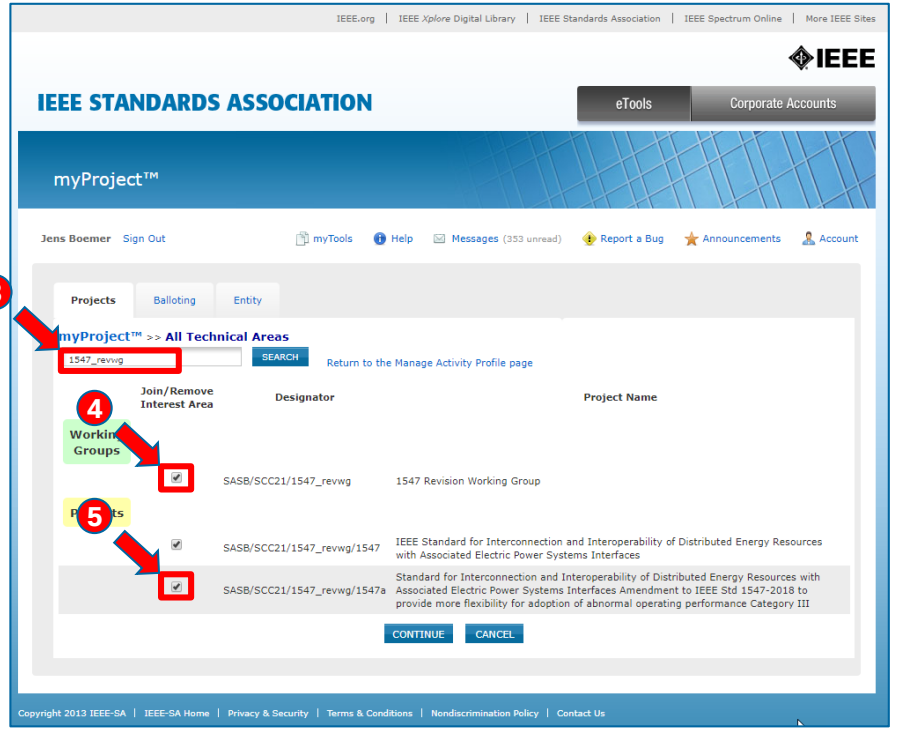
Vote	Count
Approve	32
Disapprove	1
Abstain	2

- WG Members that were unavailable on Sep 26 were able to cast their vote using iMeet: https://ieee-sa.imeetcentral.com/p/aQAAAAAD89He



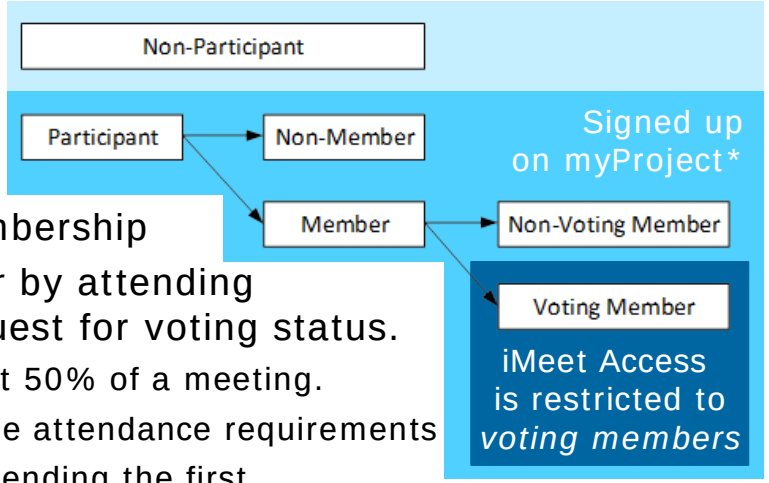
Step 1: Become a *Participant* in the P1547a Working Group and Project on myProject





WG Membership Status and iMeet Access

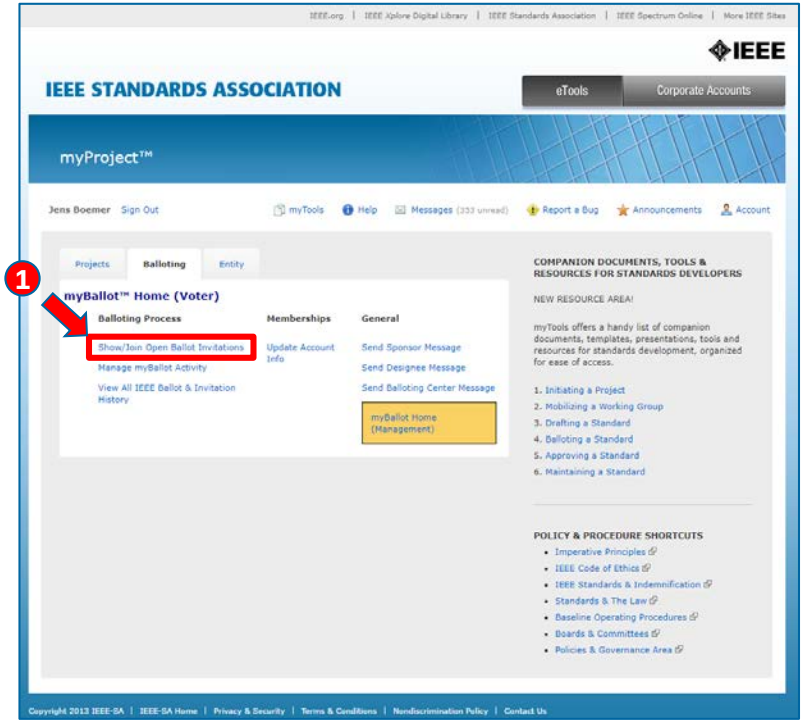
- **PnP's–Clause 4.0 Working Group Membership**
  - Working Group membership is by *individual*
  - IEEE and/or IEEE-SA membership not required
  - A *non-member* becomes a *non-voting member* by attending one meeting … and requesting membership
  - A *non-voting member* becomes a *voting member* by attending *2* of the last *4* meetings and upon sending a request for voting status.
    - Attendance credit is granted to those attending at least 50% of a meeting.
    - Attendance via teleconferencing shall count towards the attendance requirements
    - *Voting membership* is granted to those participants attending the first meeting of a newly chartered Working Group upon their request.
  - Voting member status is maintained through consistent participation and voting
    - may be revoked if a Working Group member misses two consecutive meetings
    - A member who lost voting privileges shall have them reinstated by attendance at two consecutive meetings of the Working Group and upon request for member status
    - Working Group Chair can decide in cases of personal hardship

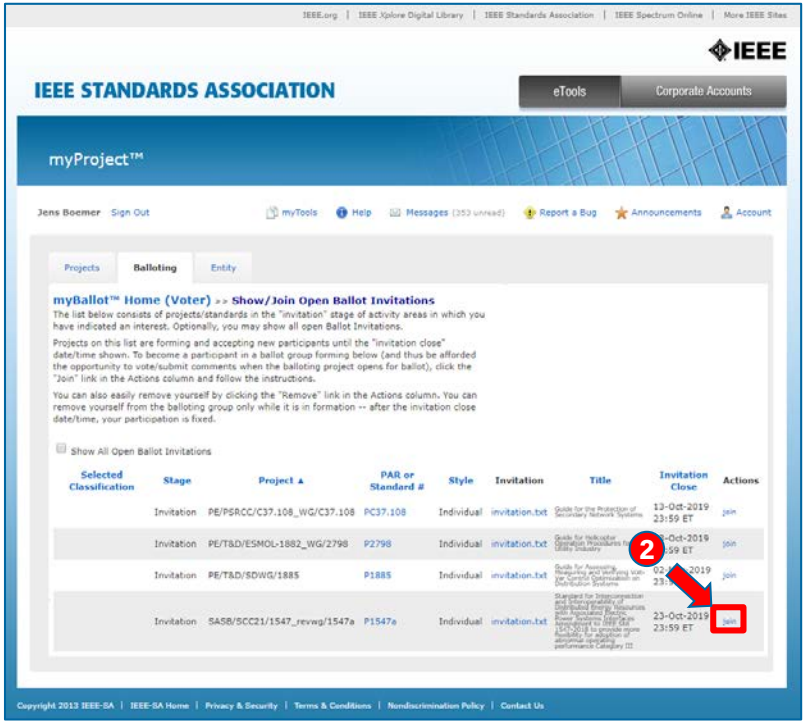


* Log WG Mtg attendance via iMAT

Step 2:
Join The Ballot Pool

Deadline: Oct 23!





Step 2: Join The Ballot Pool
If you are an IEEE-SA member

If you are an IEEE-SA member:

Go directly to:

https://development.standards.ieee.org/my-site/open-ballot-invitations [development.standards.ieee.org]

Or, follow this process:

1. Log onto myProject; click the link for myBallot.
2. Click the link for myBallot (if applicable); click the link for "Show/Join Open Ballot Invitations": https://development.standards.ieee.org/my-site/open-ballot-invitations [development.standards.ieee.org]
3. Scroll down until you find the open ballot group of interest to you; then scroll over to the right margin and click "join" under the "Actions" column.
4. Enter or select an affiliation from the drop down menu (appearing as you key in your affiliation in the Organization window), select your classification category, and click "OK" at the bottom of the screen. You will receive an on-screen confirmation that you successfully joined the group.

Step 2: Join The Ballot Pool

If you are not an IEEE SA Member

If you are not an IEEE SA Member:
You can either enroll in a single ballot by paying a per ballot fee or you can join the IEEE SA by choosing an option link below. Joining the IEEE SA entitles you to participate in as many sponsor ballots as you like for the year.

OPTION 1 - I am already an IEEE Member and I want to add Standards Association Membership. Go to: http://www.ieee.org/membership_services/index.html [ieee.org]
OPTION 2 - I am not an IEEE Member but would like to enroll in both IEEE and IEEE Standards Association. Go to:
http://www.ieee.org/membership_services/membership/join/index.html [ieee.org]
OPTION 3 - I am not interested in becoming an IEEE Member, however I would like to enroll as a Standards Association Member only. Go to: http://standards.ieee.org/sa-mem/join.html [standards.ieee.org]

Step 2: Join The Ballot Pool

Obligations And Responsibilities Of Balloters

==========
OBLIGATIONS AND RESPONSIBILITIES OF BALLOTERS
==========

Balloting group members have an obligation to respond during the balloting period; failure to return a ballot may disqualify the balloter from participation in future balloting groups.

Once the document is ready to be balloted, you will receive notification via email. You will typically have 30 days to review the document and return the ballot with your vote. By agreeing to participate in this ballot you have an *obligation* to respond. Failure to return a completed ballot may disqualify you from participating in future ballots.

Thank you for your interest in this ballot.

We Look Forward to Your Comments!

Contacts

- David Narang, David.Narang@nrel.gov
- Charlie Vartanian, charlie.vartanian@pnnl.gov
- Mark Siira, msiira@comrent.com
- Babak Enayati, Babak.Enayati@nationalgrid.com
- Jens C. Boemer, jboemer@epri.com
- John Berdner, jberdner@enphaseenergy.com
- Bob Fox, bob@sunspec.org

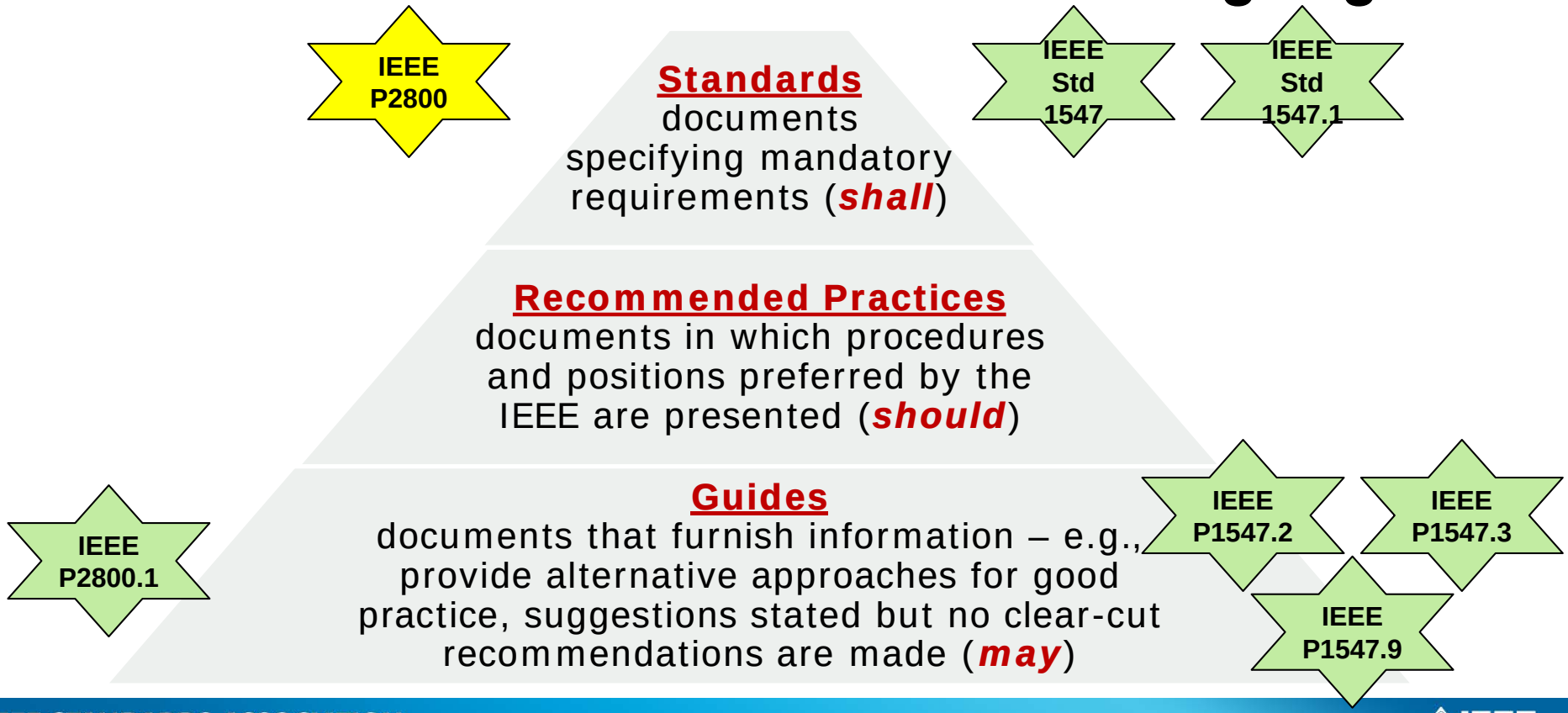
Background Information

Resources

- **Training Videos**
  - How to Run an Individual Working Group
  - How to Run an Entity Working Group

- **Bylaws and Procedures**
  - IEEE-SA Standards Board Bylaws
    -http://standards.ieee.org/develop/policies/bylaws/
  - IEEE-SA Standards Board Operations Manual
    -http://standards.ieee.org/develop/policies/opman/
  - IEEE Baseline Operational Procedures
    http://standards.ieee.org/about/sasb/audcom/bops.html

IEEE Standards Classification & Language



IEEE SA Balloting Rules

Consensus =

- ≥75% Quorum
- ≥75% Approval
  - *WG Chair's goal is ≥90%!*

IEEE P1547a Project Authorization

- ***Available online:*** https://development.standards.ieee.org/P1139500033/par
- ***Title:*** Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces – Amendment to IEEE Std 1547-2018 to provide more flexibility for adoption of abnormal operating performance Category III
- ***Scope:*** This amendment revises the ranges of allowable trip clearing time settings in Table 13 for DERs in abnormal operating performance category III. No changes are expected for the default trip settings in any of the tables and abnormal operating performance categories. Informative figure H.9 will be updated. No other changes of the language in IEEE Std 1547-2018 shall be part of this amendment.

➢ ***Approved by the IEEE SASB on September 5, 2019***

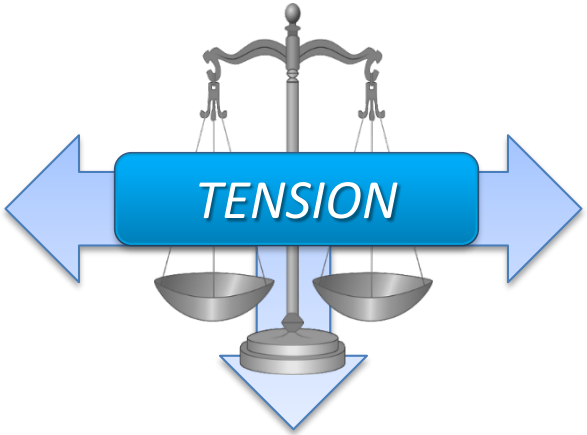
IEEE P1547a Project Authorization

- ***Purpose:*** IEEE Std 1547-2018 defines the performance and functional requirements for DER connected with the Area Electric Power Systems (Area EPS). This amendment to IEEE 1547 would widen the ranges of allowable trip settings to allow wider ranges that may broaden and simplify the adoption of the standard.
- ***Need for the Project:*** This project is needed to address needs of stakeholders who have expressed that wider ranges of allowable trip settings for UV1 and UV2 for Category III DERs (Table 13) would broaden and simply the adoption of the standard. This would allow to maintain harmonization of DER interconnection and interoperability requirements across the jurisdictions applying IEEE Std 1547-2018. The amendment is anticipated to increase the deployment of DER with Category III capabilities that can provide the highest bulk system reliability, compared to DER that is capable of the lower Category II. This amendment would allow to specify voltage trip clearing times of Category III capable DER for safe and reliable coordination with distribution protection objectives. The proposed timeline for this amendment (see the additional explanatory notes in 8.1 below) has been harmonized with the drafting of regional reliability guidelines by regional reliability coordinators in North America and the anticipated test and verification of IEEE Std 1547-2018 compliant DER equipment through the procedures specified in IEEE P1547.1 as well as the certification of inverter-based DER specified in UL 1741.

Balancing Bulk & Distribution Grid Needs

Distribution Grid Side

- Short trip times
- Ride-through *with momentary cessation*
- Voltage rise concerns
- Islanding concerns
- Protection coordination
- Safety of line workers



Bulk System Side

- Long trip times
- Ride-through *with constrained* momentary cessation
- Reactive power support
- Frequency support

Increasing need for T&D Coordination

Source: EPRI

Example Adoption of IEEE Std 1547-2018

ISO New England

- Coordination between ISO-NE and the MA's utilities in the Massachusetts Technical Standards Review Group
- Reference to UL 1741 SA as a stopgap to verify DER ride-through capability in the interim
  - Harmonization of voltage & frequency trip settings with IEEE Std 1547-2018 ranges of allowable settings
- Full adoption of IEEE Std 1547-2018 under way since early 2019

PJM Interconnection

- Two ad-hoc stakeholder workshops in 2018 for DER ride-through categories and trip settings (PJM website)
- Initiation of formal stakeholder proceedings in 2019 (PJM website)
- Published a draft reliability guideline for voluntary DER ride-through in August 2019 (PJM Website)

Minnesota Public Utilities Commission

- Phase 1 (2017): Interconnection Process, Applications, Agreements
- Phase 2 (2018): Technical Requirements consistent with IEEE Std 1547-2018 (MN PUC website)
- Coordination with regional reliability coordinator, e.g., MISO (MISO's IEEE 1547 website)
- Published a draft reliability guideline for preferred DER ride-through in September 2019 (MISO's IEEE 1547 website)

Source: EPRI

P1547a WG Draft: Partial harmonization of ranges of Category III with Category I and II (lower value only)

1. Revise lower value of Category III range of allowable settings for UV1 and UV2 clearing time.
2. Leave all Category III default settings as is.
3. Revise informative figure H.9 accordingly.

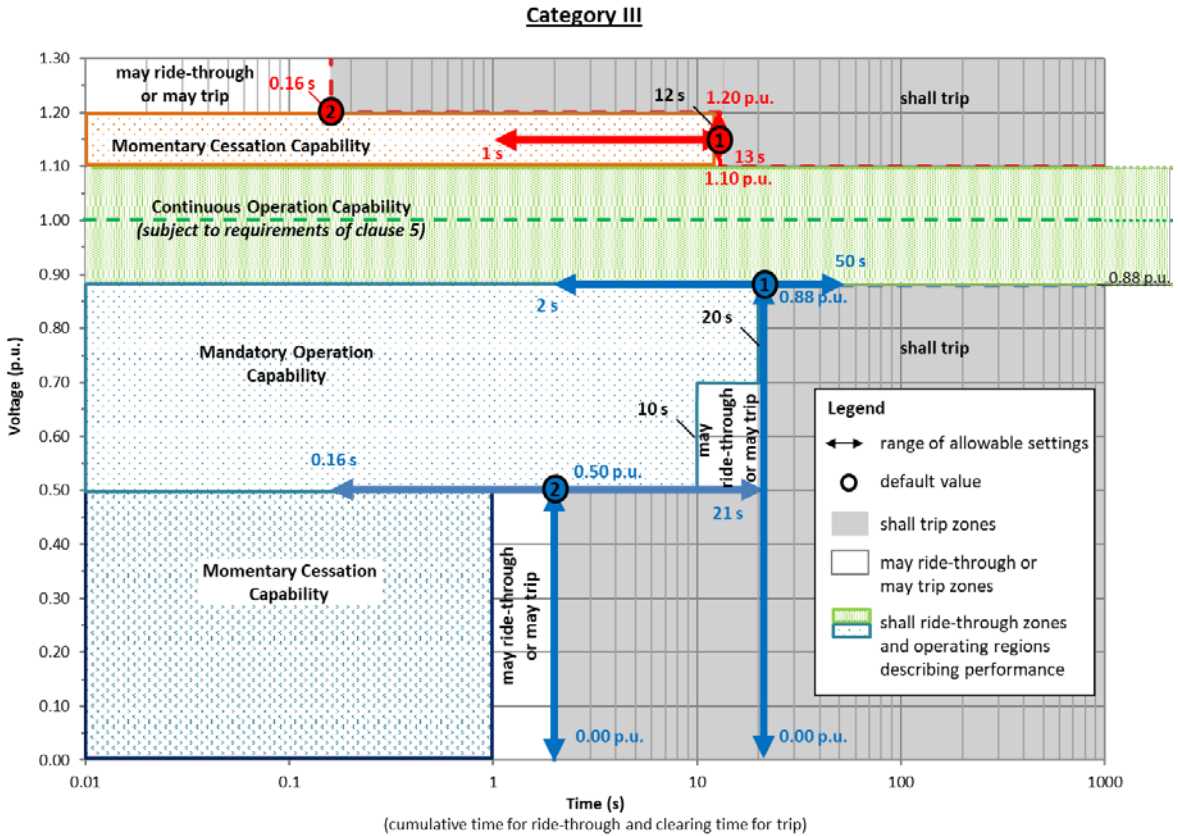
Table 13—DER response (shall trip) to abnormal voltages for DER of abnormal operating performance Category III (see Figure H.9)

Shall trip—Category III				
Shall trip function	Default settings[a]		Ranges of allowable settings[b]	
	Voltage (p.u. of nominal voltage)	Clearing time (s)	Voltage (p.u. of nominal voltage)	Clearing time (s)
OV2	1.20	0.16	fixed at 1.20	~~fixed at 0.16~~
OV1	1.10	13.0	1.10–1.20	1.0–13.0
UV1	0.88	21.0	0.0–0.88	~~21.0~~ **2.0**–50.0
UV2	0.50	2.0	0.0–0.50	~~2.0~~ **0.16**–21.0

[a]The Area EPS operator may specify other voltage and *clearing time* trip settings within the *range of allowable settings*, e,g., to consider Area EPS protection coordination.

[b]Nominal system voltages stated in ANSI C84.1, Table 1 or as otherwise defined by the Area EPS operator. The *ranges of allowable settings* do not mandate a requirement for the DER to ride through this magnitude and duration of abnormal voltage condition. The Area EPS operator may specify the voltage thresholds and maximum *clearing times* within the *ranges of allowable settings*; settings outside of these ranges shall only be allowed as necessary for DER equipment protection and shall not conflict with the voltage disturbance ride-through requirements specified in 6.4.2. For the overvoltage (OV) and undervoltage (UV) trip functions *clearing time* ranges and for the OV trip functions voltage ranges, the lower value is a limiting requirement (the setting shall not be set to lower values) and the upper value is a minimum requirement (the setting may be set above this value). For the UV trip functions voltage ranges, the upper value is a limiting requirement (the setting shall not be set to greater values) and the lower value is a minimum requirement (the setting may be set to lower values).

P1547a WG Draft: Modification to Figure H.9



1. Revise lower value of Category III range of allowable settings for UV1 and UV2 clearing time.

2. Leave all Category III default settings as is.

© Copyright IEEE 2018. All rights reserved. Adapted and reprinted with permission from IEEE.

Timeline for rollout of 1547.1 and UL 1741

Dates	Activities	Status
April 2018	**Milestone:** IEEE 1547-2018 published: New DER grid interconnection requirements established. In parallel: IEEE 1547.1 update in progress. (New test procedures to verify conformance to 1547-2018)	Complete
February 26-27, 2019	IEEE P1547.1 WG meeting – Draft 9.3 approved by Working Group	Complete
March 2019	Final pre-ballot edits to P1547.1	Complete
April 2019	**Milestone:** Final WG vote to send P1547.1 Draft 9.4 to IEEE-SA	Complete
April 2019	P1547.1 D9.4 sent to IEEE-SA for ballot invitation and MEC review	Complete
Q2-Q3 2019	IEEE-SA balloting and ballot resolution of P1547.1 (iterative)	In progress
Q4 2019	UL 1741 begin revision draft to incorporate new 1547.1 and 1547	
Q4 2019	**Milestone:** IEEE-SA ballot approval of P1547.1	
January 2020	IEEE RevCom review of P1547.1 In parallel: Finalize UL 1741 ballot document to incorporate new 1547.1.	
Q1/Q2 2020	**Milestone:** 1547.1 finalization and publication	
Q1/Q2 2020	UL Standards Technical Panel review and ballot updated UL 1741	
Q1/Q2 2020	**Approval and Publication of Amendment to IEEE Std 1547-2018**	
Q2/Q3 2020	**Milestone:** UL 1741 update published	
Q3 2020 – Q4 2021	Inverter manufacturers update and recertify products to UL 1741	
Q4 2020 – Q4 2021	UL 1741 / 1547-2018 compliant inverters expected to be available on market	

NPCC DER Forum

DER Interconnection and the Bulk Energy System

Ted Ko
Director of Policy
October 17, 2019

stem
Energy Superintelligence

Stem overview

Stem operates the world's smartest and largest digital energy storage network

Founded: **2009**

Headquarters: **San Francisco Bay Area, CA**

Employees: **150+**

Operations: **CA, HI, NY, TX, MA, Japan, Ontario**

Contracted & Installed: **1,250+ sites contracted, 380 MWh**

Execution: **600+ installations, 10M+ runtime hrs.**

Grid services: **Over 1,000 day ahead and real time calls**

Project Finance: **$650 MM**

Software Experience: **10 years, extensive data drives AI**

High caliber global investors

GE · Mitsui & Co., Ltd. · Constellation (An Exelon Company) · Ontario Teachers' Pension Plan · Angeleno Group · Activate Capital · Total · Iberdrola · Mithril · RWE · Temasek

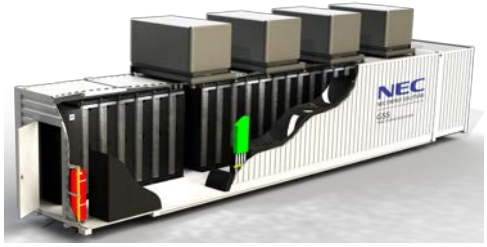
Distinguished honors and awards

SEPA Power Player 2017: Innovative Partner of the Year

World Economic Forum · Energy Excelerator · Grid Edge 20 · 2018 Global Cleantech 100 · Bloomberg New Energy Pioneers 2017 Winner · SEPA Power Players

© 2019 Confidential

Examples from Stem's Energy Storage Portfolio

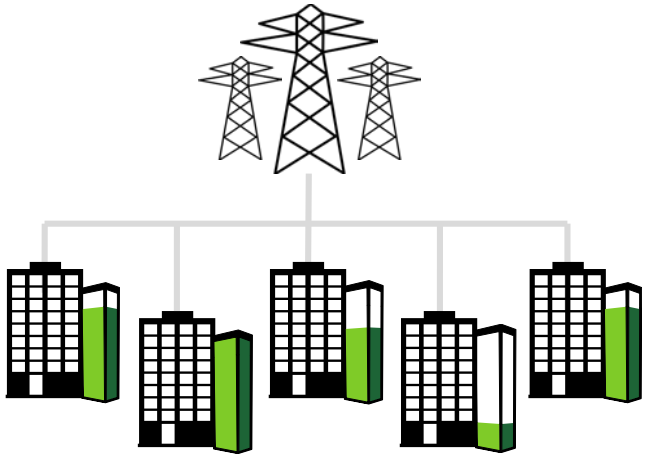


- Operating over 18 models of Energy Storage Systems from tier 1 suppliers
- From 100kW to 20MW+ offerings
- Standardized installation and integrations
- Leveraging regional EPC partners

© 2019 Confidential

Virtual Power Plants

Networked distributed storage enables large scale grid services



- Batteries aren’t being used 24x7 for the building
- Utilities and grid operators call the VPP for energy and grid services
- Artificial Intelligence software selects storage systems with spare energy

VPPs operating at scale for years

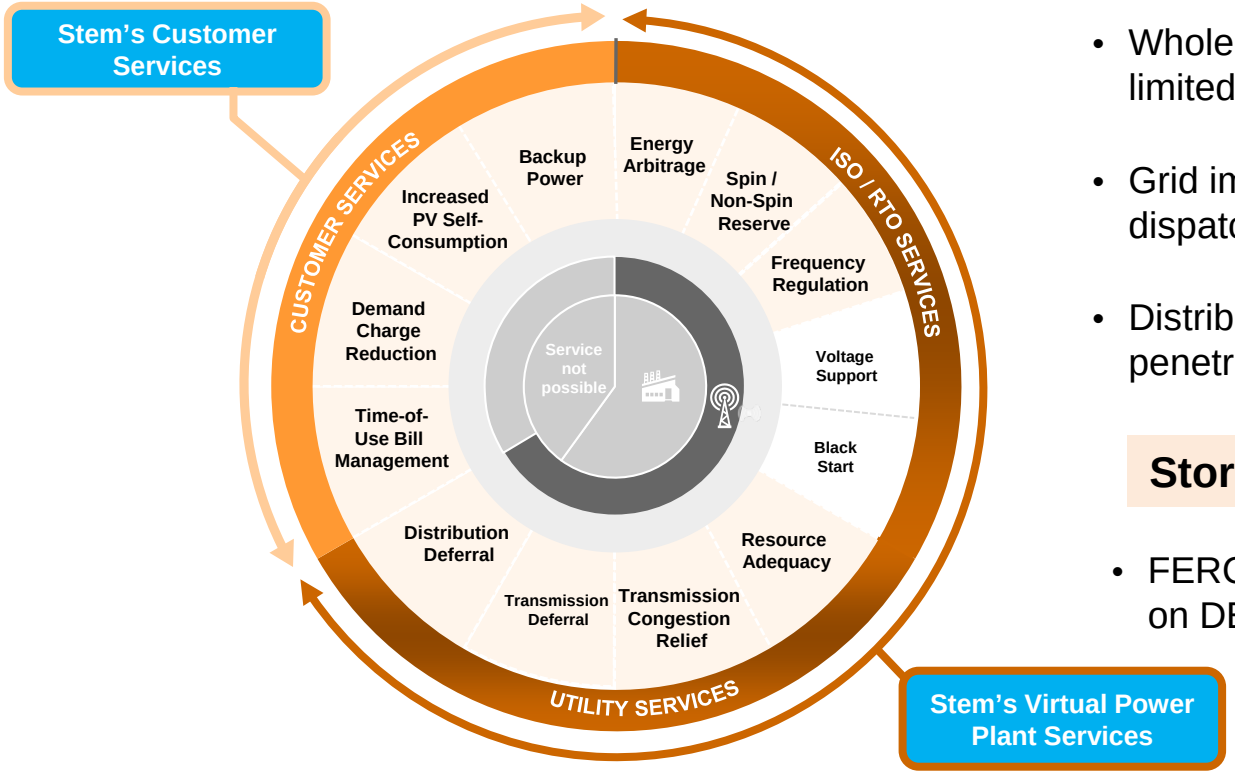
Thousands of automated dispatches in real time markets

Single dispatches can involve hundreds of buildings

stem

© 2019 Confidential

Services From Distributed Storage



- Wholesale services from DERs historically limited to Demand Response
- Grid impacts relatively small from slowly dispatched load reduction
- Distributed solar has been a low penetration, non-dispatchable load modifier

Storage changes the equation

- FERC issues Order 841 and opens docket on DER Aggregation

Source: Rocky Mountain Institute.

© 2019 Confidential

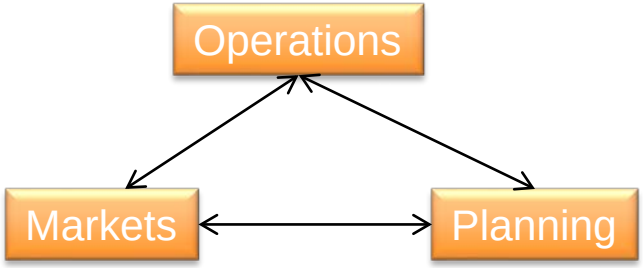
Why DER Interconnection Matters

Financial-Physical Separation

- Distribution utility cannot veto wholesale registration
- ISO should allow time for interconnection review

Reliability Independence

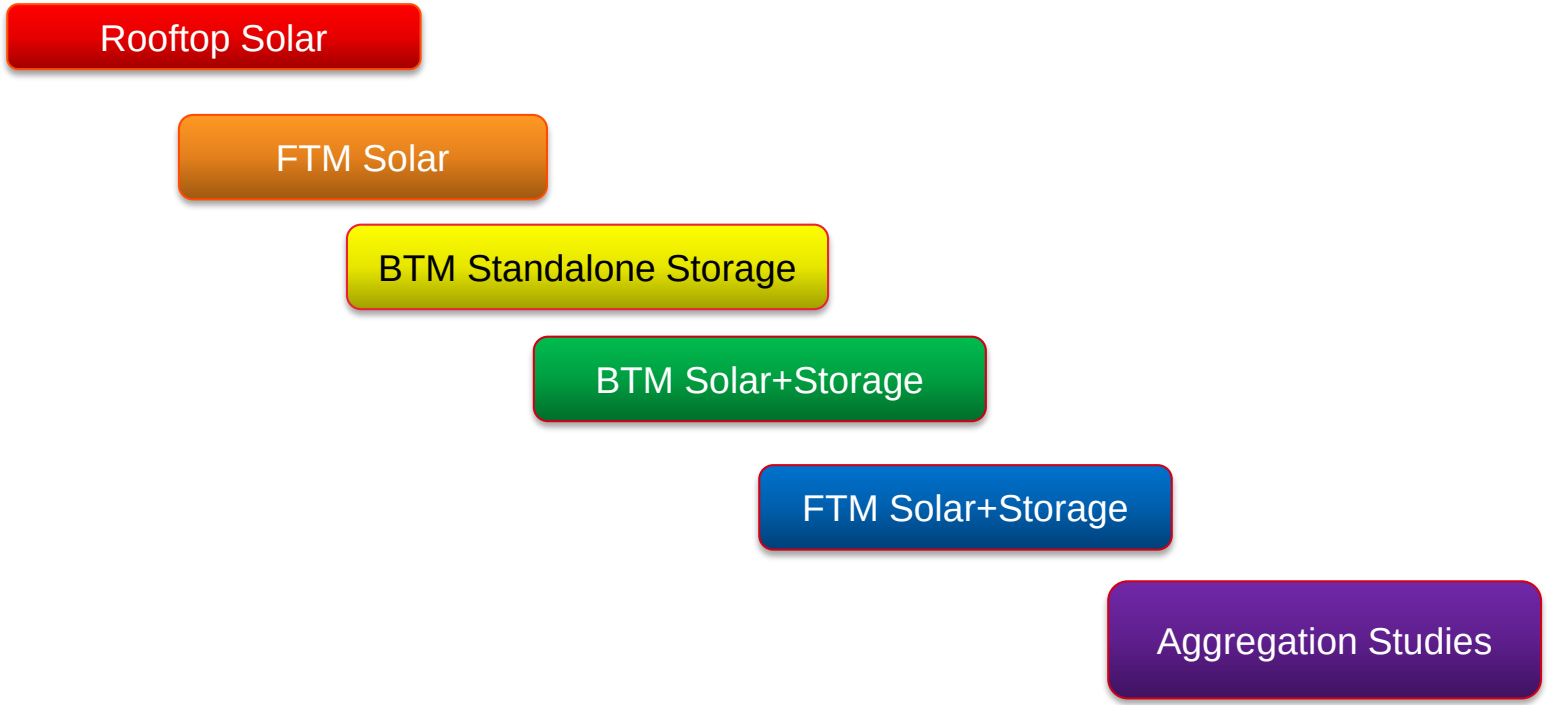
- Reliability risks are independent of wholesale transaction
- Reliability risks handled in interconnection processes and agreements
- Operational constraints communicated ongoing between distribution utility and aggregator. Aggregator communicates impacts to ISO



Interconnection is key factor in all areas

© 2019 Confidential

Evolution of DER interconnection



© 2019 Confidential

Key milestones / concepts

FTM Solar (Ontario, Canada)

- FIT drove high penetrations, need to study bulk system impacts

BTM Standalone storage (California)

- Software controls / operational profiles
- Wholesale market aggregation, under DR construct

BTM Solar + Storage (CA vs ISO-NE)

- Policies around export, NEM

FTM Solar + Storage (ISO-NE)

- Wholesale market participation

© 2019 Confidential

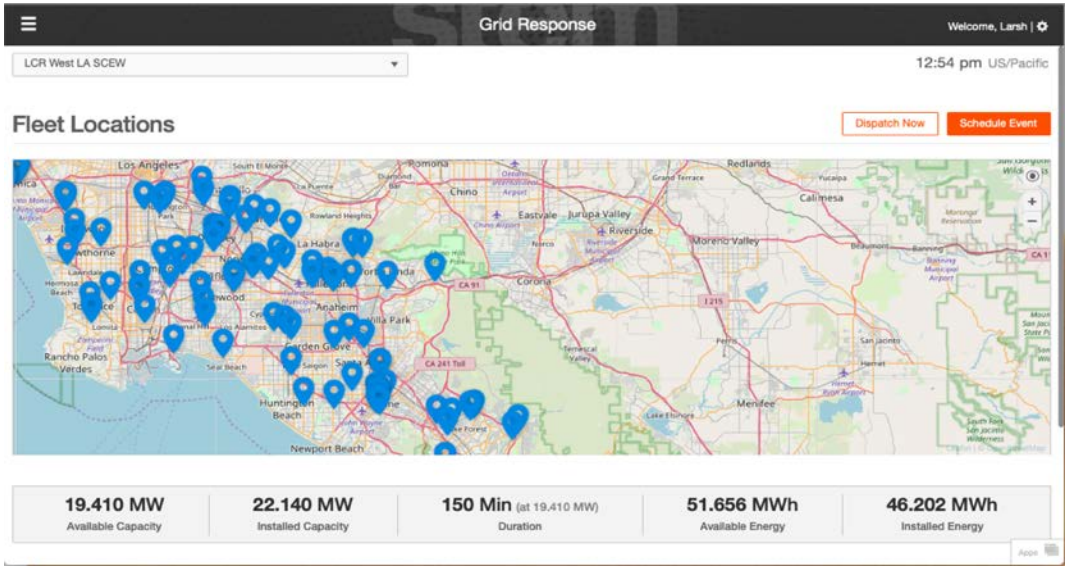
Aggregations

FERC Issued Data Request in RM19-9, ISOs responded 10/7

- Cluster studies exist but no aggregation studies
- ISO's depend on distribution utility to inform ISO of potential impacts

Distribution Interconnection

- Aggregate impacts independent of wholesale market transaction
- Not an issue with DR resources
- No utility has created an aggregation study process



© 2019 Confidential

stem
Energy Superintelligence™