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 #18-5
December 6, 2018 8:00 a.m. – 5:00 p.m. EST
The Westin Prince Toronto Hotel
NPCC General Meeting
900 York Mills Road
Toronto, Ontario
Attire: Business Casual

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

Guest Code: 648426565
Password: dRD845i* (37384540 from phones)

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated July 3, 2018
NPCC Glossary of Terms, dated January 14, 2014

Introductions and Chair's Remarks

NPCC Antitrust Compliance Guidelines

Agenda Items:

1.0 Review of Agenda

2.0 RSC Meeting Minutes

3.0 Drafting Team Members and Executive Tracking Summary

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

4.0 Open Action Items

4.1 Open Action Items List

5.0 Items Requiring RSC Discussion

5.1 NERC Weekly Standards Bulletin
5.2 NPCC CEAP
5.3 RSC Scope of Work
5.4 RSC Work Plan
5.5 NPCC Regional Standards Processes Manual Revision
5.6 FERC Activities

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	12/18/18 (I)	10/9/18 (F)
Project 2017-03 FAC-008-3 Periodic Review	12/13/17 (F)	
Project 2017-07 Standards Alignment with Registration	3/2/18 (F)	
Project 2018-01 Canadian-specific Revisions to TPL-007-2	11/15/18 (F)	12/10/18 (F)
Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	11/29/18 (F)	11/29/18 (A)
Functional Model Advisory Group	9/17/18 (I)	
Standards Efficiency Review	9/26/18 (F)	
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 Item for Approval:

9.1.1 Cost Effectiveness Revisions Directory Manual

9.2 Items for Discussion:

9.2.1 Directory#7 *SPS* and NPCC Glossary term SPS
(Status of RAS Implementation/Transition)

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

9.2.3 NPCC BOD Directive --- Strategic Review of the Need for NPCC Criteria

9.2.4 Directory#5 *Reserve* - (status of TFCO review).

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

Standards Committee (SC) 2019

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

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

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

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

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

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

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

Board of Trustees (BOT) 2019 Meeting

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 has been one new Lesson Learned issued since the last RSC meeting.

13.2 Alerts
http://www.nerc.com/pa/rrm/bpsa/Pages/Alerts.aspx
There has been no new NERC Alerts released since the last RSC meeting.

14.0 Other Items of Interest

14.1 NPCC Board of Directors Meeting (BOD) 2018

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

14.2 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

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2018 Meeting Dates

March 7th-8th, Entergy, Woodlands Texas
June 20th-21th, Saratoga NY
August 22th-23th, Montreal Canada
October 10th-11th, Lewiston NY
December 6th, Toronto Ontario

15.2 RSC 2018 Conference Call Schedule (calls can be schedule as needed) all Calls are planned to start at 10:00 a.m. (call: 415-655-0003 (USA) / 416-915-6530 (Canada), Guest Code 28840965)

January 19	February 2	February 16
March 23	April 6	April 20
May 4	May 18	June 22
July 13	July 27	August 10
September 14	September 28	October 26
November 9	November 23	December 21

15.3 RSC 2019 Meeting Dates

February 13th-14th, NextEra, Palm Beach Florida
May 15th-16th, Saratoga NY
August 14th-15th, Toronto Canada
October 16th-17th, Lewiston NY
December General Meeting

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.

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 #18-4
October 10, 2018 10:00 a.m. – 4:00 p.m. EST
October 11, 2018 8:30 a.m. – 12:00 p.m. EST
NYPA Niagara Power Project Power Vista Visitor Center
5777 Lewiston Road
Lewiston, New York
Attire: Business Casual

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

Day 1:
Guest Code: 641289945
Password: 3Jd3Tfx@ (35338391 from phones)

Day 2:
Guest Code: 644856258
Password: 8bTEPp@7 (82837717 from phones)

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated January 31, 2018
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		2	Via Phone
3.	Ruida Shu	Northeast Power Coordinating Council		1, 2	
4.	Juan Villar	FERC	Guest	1, 2	
5.	Scott Barfield	NERC	Guest	1, 2	
6.	Michael Golbout	Hydro Quebec	2	1, 2	
7	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	1, 2	Via Phone
8.	Chris Overberg	Consolidated Edison Co. of New York, Inc.	1, 3, 4 & 5	1, 2	
9.	Constantin Chitescu	Ontario Power Generation, Inc.	4	1, 2	
10.	Mike Cooke	Ontario Power Generation, Inc.	4	1, 2	

11.	Laura Mcleod	New Brunswick Power Corporation	1	1, 2	Via Phone
12.	Payam Farahbakhsh	Hydro One Networks	1	1, 2	
13.	Ben Wu	Orange & Rockland Utilities, Inc.	3	1	Via Phone
14.	David Burke	Orange & Rockland Utilities, Inc.	3	1, 2	Via Phone
15.	Brian Robinson	Utility Services, Inc.	5	1, 2	
16.	Sean Bodkin	Dominion Resources Services	4	1, 2	Via Phone
17.	Sean Lagan	IESO	Guest	1, 2	
18.	Salvatore Spagnolo	NYPA	4	1, 2	
19.	Tom Savin	NYPA	Guest	1, 2	
20.	Michele Tondalo	The United Illuminating Company	1	1, 2	Via Phone
21.	Jim Grant	NYISO	2	1, 2	
22.	David Kiguel	Independent	7	1, 2	Via Phone
23.	Sean Cavote	PSEG	4	1	
24.	Joel Charlebois	AESI	7	1, 2	
25.	Kathleen Goodman	ISO-NE	2	1	Via Phone
26.	Dean Laforest	ISO-NE	Guest	1	Via Phone
27.	Scott Klauminzer	Tacoma Hydro	Guest	1	Via Phone

Introductions and Chair's Remarks

Salvatore Spagnolo welcome everyone to Lewiston NY.

Guy Zito reminded everyone that the RSC group is soliciting two members to volunteer for the Vice Chair position for the NPCC RSC.

NPCC Antitrust Compliance Guidelines

The NPCC Antitrust Compliance Guidelines were read by Ruida Shu.

Agenda Items:

1.0 <u>Review of Agenda</u>

Guy Zito reviewed the meeting agenda with the group.

Guy Zito added agenda item 5.9 and 5.10.

2.0 <u>RSC Meeting Minutes</u>

Approval of Minutes—no additional revisions were made to the draft RSC meeting minutes of 6-20-18
Herb Schrayshuen made the motion for approval.
Brian Robinson seconded the motion.
The meeting minutes were approved as read.

3.0 Drafting Team Members and Executive Tracking Summary

3.1 NPCC Members on NERC Drafting Teams
The RSC members reviewed the roster and added several names to the list.

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

3.3 NERC Project Tracking Spreadsheet
Guy Zito provided a brief update on the 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
Guy Zito reviewed the NERC weekly standards bulletin with the RSC group.

5.2 NPCC CEAP
Guy Zito indicated that NPCC is looking into potentially adding the CEAP into the Directory Manual and Regional Standards Processes Manaul.

5.3 RSC Scope of Work
Herb Schrayshuen will assist.
Action Item: Guy, Ruida and Herb Schrayshuen will redline the draft document for review.

5.4 RSC Work Plan
Action Item: Guy, Ruida and Herb Schrayshuen will redline the draft document for review.

5.5 Project 2016-02 CIP Definitions
Ruida Shu reviewed all the latest Virtualization definitions with the RSC group. RSC members questioned on the reason for retiring the Electronic Security Perimeter and it was due to the drafting team members splitting the perimeter into logical and physical.

5.6 RISC Resilience Report
Guy Zito reviewed the RISC Resilience report with the RSC group.

5.7 Project 2018-01 TPL-007 Presentation by Hydro One
Payam Farahbakhsh gave a presentation to the RSC group, he provided a project timeline in his presentation as well as some of the high-level changes to the project.

5.8 Project 2015-09 SOL Presentation by ISO-NE
Dean Laforest called in at 10:30AM and provided a presentation to the RSC members. Dean provided a timeline for the project, overview of the changes.

5.9 NPCC Regional Standards Processes Manual Revision

Action Item: Guy Zito, Ruida Shu, Herb Schrayshuen, Quintin Lee and Mike Jones will do the initial review and redline the NPCC RSPM. Ruida Shu will combine all redline and send it to RSC members for review.
Hydro Quebec will find out if they would like to add a Canadian Variance section to the RSPM.

5.10 Standard Efficiency Review

Scott Barfield provided an overview of the Standard Efficiency Review as well as all the current active NERC projects.

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 2015-10 Single Points of Failure TPL-001	9/14/18 (F)	9/14/18 (A)
Project 2017-01 Modifications to BAL-003-1.1	9/20/18 (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	10/9/18 (I)	10/9/18 (F)
Project 2017-03 FAC-008-3 Periodic Review	12/13/17 (F)	
Project 2017-07 Standards Alignment with Registration	3/2/18 (F)	
Project 2018-01 Canadian-specific Revisions to TPL-007-2	11/15/18 (F)	11/15/18 (I)
Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	10/22/18 (F)	10/22/18 (I)
Revisions to the NERC Standard Processes Manual	8/9/18 (F)	8/9/18 (A)
Functional Model Advisory Group	9/17/18 (I)	
Standards Efficiency Review	9/26/18 (F)	
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final		

Scott Klauminzer from Tacoma Hydro called into the meeting at 2:30PM.
He reviewed the status updates on CIP-002-6, CIP-003-8, CIP-005 ad hoc Group CIP-007 and CIP-010 ad hoc Group and definitions ad hoc group.
Scott presented the new changes to CIP-007 and CIP-010.
He also presented all the new changes to the Virtualization definitions and next steps for the drafting team.

6.2 Ballot History (Since last RSC Meeting)

Ruida Shu reviewed the Ballot History document in the meeting.

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

7.0 NERC Drafting Team Nominations

7.1 Currently Posted Drafting Team Vacancies
7.1.1 None at this time
7.2 Closed Drafting Team Nominations (Since last RSC Meeting)
7.2.1 None at this time
7.3 Solicitation for Informal Development Teams
7.3.1 None at this time

8.0 NPCC Regional Reliability Standards

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

8.1 Current Activities:

8.1.1 PRC-006-NPCC-2 Automatic Underfrequency Load Shedding approval to post ballot if no significant changes are made to the existing redline.

Action Item: Ruida Shu will send out the latest redline to the RSC members for review after the drafting team meeting next week. The approval to post for ballot will be done via email approvals from the RSC members.

9.0 NPCC Non-Standards

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

9.1 Directories:

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

RAS Implementation/Transition

TFCP and TFSS continue to work on a consistent interpretation of the RAS definition.
TFCP also reviewing D#7 Appendix B to align SPS review process with PRC-012-2.
TFSP also reviewing D#7 criteria.
Anticipate Open Process posting in 2019.

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

The CP-11 Working Group has completed its testing to assess existing and alternative methodologies used to identify the most critical bulk power system facilities and will provide a recommendation on a preferred methodology to the Task Force on Coordination of Planning (TFCP) in a final report in early November.

The CP-11 effort focused on three objectives as highlighted by the TFCP in the project scope:

1) Identify critical facilities for the applicability of NPCC Directories.
2) Improve consistency of application and outcome across the region.
3) Simplify the methodology to make it less resource intensive

The Reliability Coordinating Committee (RCC) approved further testing of three proposed methodologies that were developed by CP-11 during Phase I of the review in 2017. These proposals included revisions to the existing methodology and two new methodologies

During its testing CP-11 observed that the proposed new methodologies did not adequately identify those facilities considered critical to the bulk power system.

Accordingly, the CP-11 final report concludes that the existing methodology is the most effective of these proposals in identifying those facilities critical to the design and operation of the BPS and proposes a series of improvements to the methodology in order to promote regional consistency in the application and outcome of the test.

The recommended improvements include revisions to the overall testing strategy (i.e. where to begin and conclude testing), base case setup (i.e. load levels, interface stress and generation patterns) and the use of performance requirements to assess testing outcomes.

Additionally, since the recommended preferred methodology will continue to identify a list of critical buses, CP-11 also advocates for a new set of criteria within the methodology for the determination of element applicability to Directory#1.

Subsequent to the TFCP endorsement and RCC approval of the recommended methodology revisions to the A-10 document will be developed for Member comment and approval.

9.1.3 NPCC BOD Directive --- Strategic Review of the Need for NPCC Criteria

The NPCC Board of Directors (BOD) has requested a high-level strategic review of the NPCC Regional Reliability Criteria to determine if there is still a need for the criteria given the overall enhancements and strengthening of the NERC Reliability Standards.

An initial draft of the Strategic Review was developed and circulated to the NPCC Task Force on Coordination of Operation (TFCO), the Task Force on Coordination of Planning (TFCP), the Task Force on System Protection (TFSP) and the Task Force on System Studies (TFSS).

The report was organized according to broad reliability functions and provided an assessment of the criteria in Planning, Protection and Operations.

In summary, the Task Force responses supported the conclusion that the NPCC Criteria contributes to the reliable design, operation and resilience of the NPCC Bulk Power System (BPS) beyond what the NERC Reliability Standards provide.

The report also concludes that during the Task Force review of each Directory an additional evaluation that considers the incremental reliability benefit of the criteria should be undertaken by the Task Force having jurisdiction over the criteria and the results of such a review should be documented.

Subsequent to an additional RCC and RSC comment period, a final report will be submitted to the TFCP in November and will be forwarded to the RCC and the RSC for consideration at their December 2018 meetings.

9.1.4 Directory#5 *Reserve* - (status of TFCO review).

TFCO and the CO1 Working Group currently reviewing criteria and reformatting into NERC style requirements. Anticipate Open Process posting in 2019.

9.1.5 Directory#8 System Restoration ---- Additional TFCO Revisions

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

Open Process Comment Review and RSC Approval of Revised Manual

In accordance with Section VIII of the NPCC Amended and Restated by- Laws dated January 1st, 2012 the NPCC Full Member Committee has voted to approve the following ballot proposals effective September 25, 2018:

Directory #8 System Restoration --- Revised:
Revisions to Section 1.7 of the document to better align the criteria with the requirements of PRC-006-6 Protection System, Automatic Reclosing and Sudden Pressure Relaying Maintenance.

A-01 Criteria for Review and Approval of Documents --- Retired:
Retirement of the A-01 which will be incorporated into the NPCC Directory Development and Revision Manual to achieve administrative efficiency.

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 17th – Call	February 14th – Call	March 14th – Meeting
April 18th – Call	May 16th – Call	June 13th – Meeting
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Standards Committee (SC) 2019

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

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

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

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

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

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

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

Board of Trustees (BOT) 2019 Meeting

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 five 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) 2018

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

14.2 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

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2018 Meeting Dates

March 7th-8th, Entergy, Woodlands Texas
June 20th-21th, Saratoga NY
August 22th-23th, Montreal Canada
October 10th-11th, Lewiston NY

December 6th, Toronto Ontario

15.2 RSC 2018 Conference Call Schedule (calls can be schedule as needed) all Calls are planned to start at 10:00 a.m. (call: 415-655-0003 (USA) / 416-915-6530 (Canada), Guest Code 28840965)

January 19	February 2	February 16
March 23	April 6	April 20
May 4	May 18	June 22
July 13	July 27	August 10
September 14	September 28	October 26
November 9	November 23	December 21

The meeting is adjourned at 11:12AM on October 11, 2018.

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		
2016-01	Modifications to TOP and IRO Standards - TOP-001, IRO-002	Standard				
2016-02	Modification to CIP Standards	Standard	Steve Brain	Dominion Resource Services, Inc.		
2016-04	Modifications to PRC-025-1	Standard	Juan Alvarez	Utility Services		
2016-EPR-01	Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards	Standard	Tim Kucey	PSEG Fossil, LLC		
2017-01	Modifications to BAL-003-1.1	Standard	Jessica Tang	IESO		
2017-02	Modifications to Personnel Performance, Training, and Qualifications Standards - PER-003, PER-004	Standard				
2017-06	Modifications to BAL-002-2	Standard				
2017-07	Standards Alignment with Registration	Standard	Mark Atkins	AESI		
2018-01	Canadian-specific Revisions to TPL-007-2	Standard	Majid Fassi Fehri Louis Gibson Steve Burns Cynthia Yiu Phillip Hiusser	Hydro Quebec Hydro Quebec IESO Hydro One OPG		
2018-02	2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	Standard	Norm Dang Steve Brian	IESO Dominion Resource Services, Inc.		
Source = NERC Standard Drafting Team Rosters - July 2017						

NPCC Directory Executive Tracking Summary

Revised: **11/1/2018** Further details regarding the individual documents may be found at: https://www.npcc.org/Standards/SitePages/NonStandardsList.aspx

Line No.	Type	Document	Description	Latest Revision	Comments	Status

NPCC Directory Executive Tracking Summary

Revised: **11/1/2018**

	Document	Developed From	Title of Directory	Responsible Task Force	Latest Version	Comments	Status
	Directory #1	Criteria A-2	Design and Operation of the Bulk Power System	TFCP	Oct-15		
	Directory #2	Criteria A-3	Emergency Operations	TFCO	Jun-18		
	Directory #3	Criteria A-4	Maintenance Criteria for Bulk Power System Protection	TFSP	Jun-09		Directory#3 retired effective April 1st, 2015 coinciding with the enforcement date of PRC -005-2.
	Directory #4	Criteria A-5	Bulk Power System Protection Criteria	TFSP	Sep-15		Currently Under TFSP Review.
	Directory #5	Criteria A-6	Reserve	TFCO	Oct-12		Currently Under TFCO Review.
	Directory #6		Regional Reserve Sharing		Apr-12		
	Directory #7	Criteria A-11	Special Protection Systems	TFSP	Jul-13	TFSP Reviewing D#7 Criteria; TFCP Coordinating Review of D#7 Attachment B.	Currently Under TFCP and TFSP Review.
	Directory #8	Criteria A-12	System Restoration	TFCO	Sep-18	TFCO/TFSP Revisions.	Revisions Approved by Full Members September 25, 2018
	Directory #9	Criteria A-13	Verification of Generator Gross and Net Real Power Capability	TFCO	Dec-11		NPCC Full Members approved retirement of D#9 and D#10 pending full enforcement of MOD-25-2. (July 2019).
	Directory #10	Criteria A-14	Verification of Generator Gross and Net Reactive Power Capability	TFCO	Dec-11		See D#9.
	A-10 Criteria	N/A	Classification of BPS Elements	TFCP	Dec-09	Anticipate Revised A-10 to be Posted in 2019.	CP-11 Recommended Improvements to Existing Methodology to Promote Regional Consistency.
	A-01 Criteria	N/A	Criteria for Review and Approval of Documents	TFCP	Oct-17	Relevant A-01 Content Transferrred to Directory Manual	A-01 Retired on September 25, 2018.
Procedures							
	C-25 Procedure	N/A	Procedure to Collect Power System Event Data for Analysis of System Performance	TFSS	Retire	TFSS Proposing to Retire C-25	Pending Open Process Comment Period
	C-33 Procedure	N/A	Procedure for Analysis and Classification of Dynamic Control Systems	TFSS	Retire	TFSS Proposing to Retire C-33	Pending Open Process Comment Period
	C-46 Procedure	N/A	Procedure for Operations Planning Model Data Exchange	TFCO	New		Approved August 15, 2018
	C-47 Procedure	N/A	Event Replication Base Case Development Procedure	TFSS	New	TFSS Proposing New Document	Pending Open Process Comment Period

NPCC Directory Criteria Clarifications

Revised: **11/1/2018** Further details regarding the individual documents may be found at: https://www.npcc.org/Standards/Directory%20Interpretations/Forms/Public%20List.aspx

Line No.	Document	Title of Directory	Date Final	Task Force Review	Posted Open Process?	RCC Approval	Comments	Status
1	Directory #8 Interpretation	System Restoration	6/18/2012	TFCO	N/A	N/A	Interpretation on behalf of the NYSRC	Complete
2	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	8/28/2012	TFSP	N/A	N/A	Interpretation on behalf of Bangor Hydro	Complete
3	Directory #3 Interpretation	Maintenance Criteria for Bulk Power System Protection	12/14/2012	TFSP	N/A	N/A	Interpretation on behalf of Con Ed	Complete
4	Directory #3 Interpretation	Maintenance Criteria for Bulk Power System Protection	2/15/2013	TFSP	N/A	N/A	Response Clarified - Interpretation on behalf of Acumen Engineered Solutions	Complete
5	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	10/25/2013	TFSP	N/A	N/A	Interpretation on behalf of Hydro One Networks	Complete
6	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	3/4/2015	TFSP	Yes	Yes	Interpretation on behalf of IESO-MACD	Complete.
7	Directory#8 Clarification	System Restoration	12/1/2015	TFCO	Yes	Yes	Clarification on Behalf of OPG.	Complete.
8	Directory#5 Clarification	Reserve	9/7/2016	TFCO	Yes	Yes	Clarification on Behalf of the NYISO.	Complete
9	Directory#1 Clarification	Design and Operation of the BPS	9/7/2016	TFCP	Yes	Yes	Clarification on Behalf of New Brunswick	Complete
10	Directory#4 Clarification	System Protection Criteria	12/2/2016	TFSP	Yes	Yes	Clarification on Behalf of Eversource	Complete
11	Directory #4 Clarification	System Protection Criteria	12/5/2017	TFSP	Yes	Yes	Clarification on Behalf of Eversource.	Complete
12	Directory#1 Clarification	Design and Operation of the BPS	5/30/2018	TFCP/TFCO	Yes	Yes	Clarification on Behalf of NYSRC	Complete

11/1/2018

Filing Period	Filing Due	Filing Submitted	Comments
October 1 to December 31, 2012	3/1/2013	**3/1/2013**	**This filing is NPCC's initial quarterly filing covering the October 1 to December 31, 2012 period and covers the changes to the NPCC Criteria as a result of voting by the Full Members of NPCC.**
January 1 to March 31, 2013	6/1/2013	N/A	No changes were made during the refeenced period which required filing.
April 1 to June 30, 2013	9/1/2013	N/A	No changes were made during the referenced period which required filing.
July 1 to September 30, 2013	12/1/2013	**11/25/2013**	**Revisions to D#7 and D#12 approved by the Full Members on 7/9/2013.**
October 1 to December 31, 2013	3/1/2014	N/A	No changes were made during the referenced period which required filing.
January 1 to March 31, 2014	6/1/2014	N/A	No changes were made during the referenced period which required filing.
April 1 to June 30, 2014	9/1/2014	N/A	No changes were made during the referenced period which required filing.
July 1 to September 30, 2014	12/1/2014	N/A	No changes were made during the referenced period which required filing.
October 1 to December 31, 2014	3/1/2015	**2/23/2015**	**(1) 10/15/14 NPCC Full Members approved retirement of D#3 effective 4/01/15 coinciding with enforcement date of PRC -005-2.**
	3/1/2015	N/A	(2) 10/6/14 the RSC approved revisions to the Directory Manual which incorporated cost considerations into the Manual.
January 1st to March 31st 2015	6/1/2015	N/A	No changes were made during the referenced period which required filing.
April 1st to June 30th 2015	9/1/2015	N/A	No changes were made during the referenced period which required filing.
July 1 to September 30, 2015	12/1/2015	**11/25/2015**	**Revisions to D#1 and D#4 approved by the Full Members on 9/30/2015.**
October 1 to December 31, 2015	3/1/2016	N/A	No changes were made during the referenced period which required filing.
January 1st to March 31st, 2016	6/1/2016	N/A	No changes were made during the referenced period which required filing.
April 1 to June 30, 2016	9/1/2016	N/A	No changes were made during the referenced period which required filing.
July 1 to September 30, 2016	12/1/2016	N/A	No changes were made during the referenced period which required filing.
October 1 to December 31, 2016	3/1/2017	**2/28/2017**	**Directory#11 approved by Full Members October 2016.**
January 1st to March 31st 2017	6/1/2017	N/A	No changes were made during the referenced period which required filing.
April 1st to June 30th, 2017	9/1/2017	**Will Not Be Filed.**	**Revisions to the A-01 Document approved by the Full Members on 4/21/2017.**
July 1 to September 30, 2017	12/1/2017	**2/28/2018**	**On August 3, 2017 NPCC Full Members approved retirement of Directories #9 and #10 effective July 1, 2019**
October 1 to December 31, 2017	3/1/2018	**2/28/2018**	**Revisions to D#8 approved by the Full Members on 10/06/2017.**
January 1st to March 31st, 2018	6/1/2018	N/A	No changes were made during the referenced period which required filing.
April 1st to June 30th, 2018	9/1/2018	**30-Aug-18**	**Revisions to Directory #2 approved by the Full Members on 6/29/2018.**
July 1 to September 30, 2018	12/1/2018	Pending	Revisions to D#8 and Retirement of A-01 approved by the Full Members on 9/25/2018
October 1 to December 31, 2018	3/1/2019	N/A	No changes were made during the referenced period which required filing.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

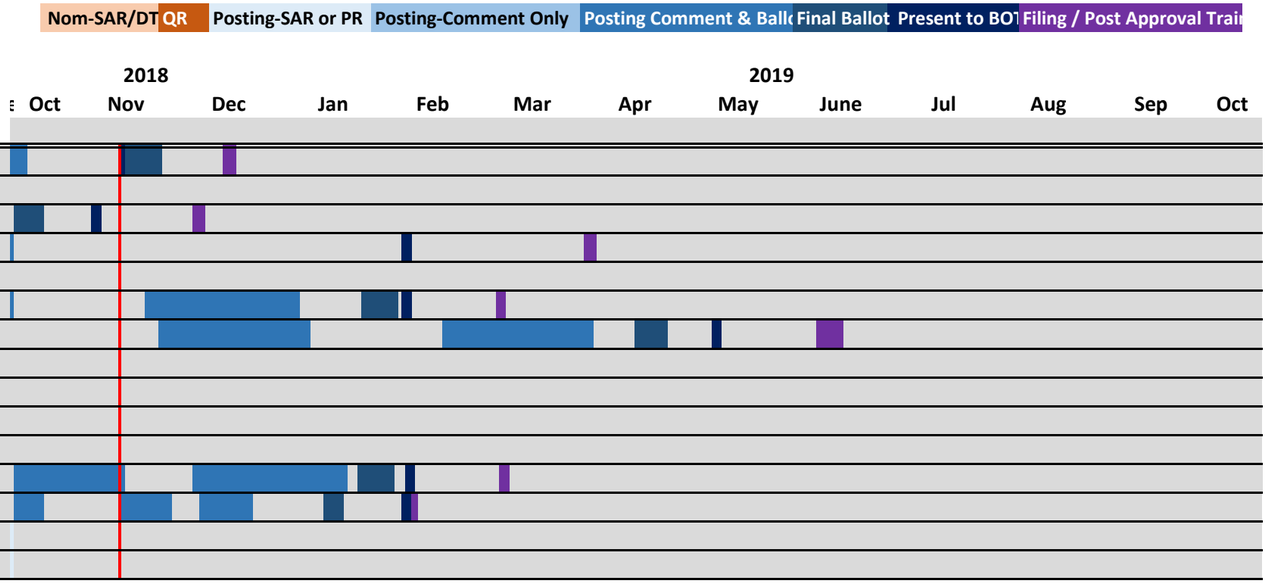
SUMMARY
Tutorial Video (11 min)
Click here to report errors or issues

Updated: 11/14/2018

Nom-SAR/DT | QR | Posting-SAR or PR | Posting-Comment Only | Posting Comment & Ballo | Final Ballot | Present to BOT | Filing / Post Approval Trail

HOME

Project (Filter)	Deliverables (Filter)	Early/(Late) Days (Filter)	Baseline/ Current (Filter)
2015-09 - Establish and Communicate System Operating	CIP-014-3, FAC-003-5, FAC-013	(228)	Current
2015-09 - Establish and Communicate System Operating	IROL Stds.		N/A
2015-10 - Single Points of Failure TPL-001	TPL-001-5	(276)	Current
2016-02 - Modifications to CIP Standards	Address TO Control Centers Pe	(465)	Current
2016-02 - Modifications to CIP Standards	Address all remaining V5TAG is	No schedule	N/A
2016-02 - Modifications to CIP Standards	CIP-003-8 (FERC Order No. 843	No schedule	N/A
2017-01 - Modifications to BAL-003-1.1	BAL-003-2		Proposed
2017-03 - Periodic Review of FAC-008-3 Standard	PR Recommendations		N/A
2017-04 - Periodic Review of Interchange Scheduling and	PR Recommendations		N/A
2017-05 - Periodic Review NUC-001-3	PR Recommendations		N/A
2017-07 - Stds Alignment with Registration	Standards with PSE, IA, or LSE		Proposed
2018-01 - Canadian-specific Revisions to TPL-007-2	TPL-007-3		Proposed
2018-02 - Modifications to CIP-008 Cyber Security Incide	CIP-008-6		Proposed
2018-03 - Standards Efficiency Review - Phase I	Retirements Only		Proposed
Standards Efficiency Review - Phase 1	Retirement of various requiren		N/A



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 standards were posted for formal comment through October 17, 2018 (extended from the 9th). The SDT plans to meet with the CIP SDT in November 6-8 to coordinate alignment with CIP-002.	CIP-014-3, FAC-003-5, 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	N/A	N/A	Latrice Harkness & Darrel Richardson	Ken Lanehome	CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-1 and the retirement of FAC-010	11/14/2018
2015-09	Establish and Communicate System Operating Limits	On Hold	The IROL portion of the project has been placed on hold pending additional information.	IROL Stds.	N/A	Medium	N/A	N/A	N/A	N/A	Al McMeekin	TBD - On Hold	TBD - On Hold	11/14/2018
2015-10	Single Points of Failure TPL-001	Pending Regulatory Filing	The standard was posted through September 22, 2018 and was approved by industry with a 66.67% vote. The standard was adopted by the NERC Board of Trustees at its November 2018 meeting. Next step is to filing with regulatory authorities.	TPL-001-5	N/A	Footnote 8, High	N/A	2 directives at P40 & P89 (Click this link for FERC Order)	N/A	N/A	Latrice Harkness	Mark Pratt	TPL-001-4	11/14/2018
2016-02	Modifications to CIP Standards	Responding to Comment	The SDT will be meeting with the 2015-9 SOL SDT on November 6-8 to align the CIP-002 standard with the SOL work.	Address TO Control Centers Performing Transmission Operator (TOP) Obligations.	N/A	Footnote 8, High	N/A	N/A	N/A	N/A	Jordan Mallory	Ken Lanehome, Ash Mayfield, and Kirk Rosener	CIP-002-5.1a	11/14/2018
2016-02	Modifications to CIP Standards	Posted	The SDT will be posting for a 45-day informal comment period on November 2 through December 18, 2018.	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.	N/A	Footnote 8, High	N/A	N/A	N/A	N/A	Jordan Mallory	Ken Lanehome, Ash Mayfield, and Kirk Rosener	CIP-005, CIP-007 and CIP-010	11/14/2018
2016-02	Modifications to CIP Standards	Responding to Comment	The CIP-003 standard was posted for comment and initial ballot through October 9, 2018. The ballot passed at 90.06%. The drafting team will meet through November and December to respond to comments and to determine next steps.	CIP-003-8 (FERC Order No. 843 Malicious Code Example Directive)	N/A	Footnote 8, High	N/A	N/A	N/A	N/A	Jordan Mallory	Ken Lanehome, Ash Mayfield, and Kirk Rosener	CIP-003-7	11/14/2018
2017-01	Modifications to BAL-003-1.1	Pending SC Action	The SDT held a conference call on October 19 to finalize documentation for authorization of a formal posting for comment and initial ballot to the SC at its November meeting.	BAL-003-2	N/A	Footnote 8, Medium	N/A	N/A	N/A	N/A	Laura Anderson	Amy Casuscelli & Linda Lynch	BAL-003-1.1	11/14/2018
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	N/A	N/A	Al McMeekin	Mark Pratt	FAC-008-3	11/14/2018

2017-04	Periodic Review of Interchange Scheduling and Coordination Standards	On Hold	The response to comments are complete. Comments were in favor of the recommendations being made by the team which is to retire one standard and drop terms which are unclear in the standards. Periodic Review of subset INT Standards will provide the Standards Efficiency Review Team (SER) (Gary Nolan is the contact person) with the initial recommendations of the INT periodic review team, as well as all associated documents this week. No future meetings or postings expected for now. Project 2017-04 will then be placed on hold pending Standards Efficiency Review team recommendations/findings. No recommendations have been made to the Standards Committee.	PR Recommendations	N/A	Footnote 9, Low (was Medium previously)	N/A	N/A	N/A	N/A	Laura Anderson	Charles Yeung	INT-004, INT-006, INT-009, and INT-010	11/14/2018
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	N/A	N/A	Mat Bunch	Amy Casuscelli and Colby Bellville	NUC-001-3	11/14/2018
2017-07	Stds Alignment with Registration	On Hold	The project is on a temporary hold for coordination with other projects (such as Standards Efficiency Review and CIP) because many of the requirements that address these functional entities, are being considered for retirement. 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). This project is not addressing a reliability issue and has a low priority in the RSDP; therefore, the project is in a holding pattern in the interim.	Standards with PSE, IA, or LSE		Footnote 9, Low	N/A	N/A	N/A	N/A	Laura Anderson	Mike Brytowski	Standards with PSE, IA, or LSE	11/14/2018
2018-01	Canadian-specific Revisions to TPL-007-2	Posted	The team met in September to respond to stakeholder comments. The standard is posted for a 45-day initial comment period and initial ballot through November 15, 2018.	TPL-007-3	N/A	Footnote 10, Medium	N/A	N/A	N/A	N/A	Mat Bunch	Charles Yeung	TPL-007-2	11/14/2018
2018-02	Modifications to CIP-008 Cyber Security Incident Reporting	Posted	The abbreviated comment period and initial ballot ended on October 22, 2018. The ballot failed considerably at 20.02%. NOTE: The second posting is scheduled for November 14, 2018. The comment period and ballot period considerably shorter to be able to work toward the January 2019 deadline.	CIP-008-6	1/19/2019	Footnote 10, High	N/A	Order No. 848 (1 Directive, 4 elements)	N/A	N/A	Alison Oswald	Colby Bellville & Amy Casuscelli	CIP-008-5	11/14/2018
2018-03	Standards Efficiency Review - Phase I	Nominations		Retirements Only		N/A	N/A	N/A	N/A	N/A	Laura Anderson	Mark Pratt & Michael Brytowski	Various	11/14/2018
Standards Efficiency Review	Phase 1	SAR	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.	Retirement of various requirements	N/A	N/A, not priorized in the RSDP	(Ops Plan) Amy Casuscelli & Charles Yeung	(RT Ops) Mike Brytowski	(LT Plan) Linda Lynch	N/A	Chris Larson	Mark Pratt & Michael Brytowski	See SAR (too many to list)	11/14/2018

Project	**Standards Efficiency Review**	**Home**
Project Name	Phase 1	
Status	SAR	
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	Retirement of various requirements	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	N/A, not priorized in the RSDP	
Operations Planning Subteam	(Ops Plan) Amy Casuscelli & Charles Yeung	
Real-time Operations Subteam	(RT Ops) Mike Brytowski	
Long-term Planning Subteam	(LT Plan) Linda Lynch	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Chris Larson	
Primary PMOS Liaison(s)	Mark Pratt & Michael Brytowski	
Affected Standards	See SAR (too many to list)	
Last Updated	11/14/2018	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	11/14/2017	11/30/2017					
Nominations - DT	8/28/2018	9/17/2018					
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	8/28/2018	9/26/2018					
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	6/7/2018	7/10/2018					
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							

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

PTS Change Control

Reason for Update	Date	Notes

Project	**2015-09**
Project Name	Establish and Communicate System Operating Limits
Status	Working to Additional Ballot
Comments	The standards were posted for formal comment through October 17, 2018 (extended from the 9th). The SDT plans to meet with the CIP SDT in November 6-8 to coordinate alignment with CIP-002.
Deliverable	CIP-014-3, FAC-003-5, 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
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	CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-1 and the retirement of FAC-010
Last Updated	11/14/2018

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review			4/4/2016	4/14/2016		Not needed	
SP1 - SAR/PR/WP Posting 1	8/20/2015	9/21/2015	8/20/2015	9/21/2015			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	7/14/2016	8/12/2016	7/8/2016	8/7/2016	(6)		
CP2 - Comment Period 2							

CIB - Com/Ballot 1 (Initial)	9/29/2017	11/13/2017	9/22/2017	11/5/2017	(7)		Posting date changed see notes 8/10 and 8/25.
CAB - Com/Add Ballot 2	4/9/2018	5/24/2018	1/17/2018	3/2/2018	(82)		
CAB - Com/Add Ballot 3	8/24/2018	10/17/2018					not in original baseline
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	11/16/2018	11/26/2018	4/2/2018	4/12/2018	(228)		
PTB - Present to BOT	11/15/2018	11/17/2018	5/1/2018	5/3/2018	(198)		
Filing - Filing with Regulators	12/15/2018	12/18/2018	6/1/2018	6/4/2018	(197)		
PT - Post Approval Training							

PTS Change Control

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

Project	**2015-09**	**Home**
Project Name	Establish and Communicate System Operating Limits	
Status	On Hold	
Comments	The IROL portion of the project has been placed on hold pending additional information.	
Deliverable	IROL Stds.	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Medium	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Al McMeekin	
PMOS Liaison	TBD - On Hold	
Affected Standards	TBD - On Hold	
Last Updated	11/14/2018	

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							
CAB - Com/Add Ballot 5							

FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Bifurcate Project	3/31/2017	Split the IRO portion into this section for tracking.
Worksheet created	8/10/2017	PMOS suggested visibility on this IROL portion.
Worksheet made visible	4/25/2018	PMOS requested that the IRO portion be tracked going forward.

Project	**2015-10**
Project Name	Single Points of Failure TPL-001
Status	Pending Regulatory Filing
Comments	The standard was posted through September 22, 2018 and was approved by industry with a 66.67% vote. The standard was adopted by the NERC Board of Trustees at its November 2018 meeting. Next step is to filing with regulatory authorities.
Deliverable	TPL-001-5
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, High
P81 Req (2013)	N/A
Number of Directives	2 directives at P40 & P89 (Click this link for FERC Order)
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Latrice Harkness
PMOS Liaison	Mark Pratt
Affected Standards	TPL-001-4
Last Updated	11/14/2018

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	11/12/2015	12/1/2015	1/18/2016	2/1/2016	67		
Nominations - DT	7/22/2016	8/5/2016	7/25/2016	8/8/2016	3		
QR - Quality Review			5/30/2016	6/9/2016			
SP1 - SAR/PR/WP Posting 1	11/12/2015	12/17/2015	11/12/2015	12/17/2015			
SP2 - SAR/PR/WP Posting 2	5/26/2016	6/24/2016	6/15/2016	7/15/2016	20	Expanded Scope	

CP1 - Comment Period 1	4/25/2017	5/24/2017	4/25/2017	5/24/2017		Other	Team added informal comment period
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/8/2017	10/23/2017	7/5/2017	8/18/2017	(65)		Held at 9/7 to stagger 2013-03 and 2015-09.
CAB - Com/Add Ballot 2	2/23/2018	4/23/2018	10/18/2017	12/1/2017	(128)		Period extended from 4/9 to 4/23 due to changes
CAB - Com/Add Ballot 3	7/30/2018	9/14/2018					Additional period
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	10/11/2018	10/22/2018	1/8/2018	1/17/2018	(276)		
PTB - Present to BOT	11/6/2018	11/8/2018	2/1/2018	2/3/2018	(278)		
Filing - Filing with Regulators	12/6/2018	12/9/2018	3/1/2018	3/4/2018	(280)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Expansion of Scope	6/14/2016	FERC directives added (P40 & P89) additional scoping in addition to industry comments following the second SAR posting. The MOD references are being updated due to some retiring
Developer change	1/13/2017	Transition from Lacey Ourso to Soo Jin Kim until a new developer is assigned.
Accept Schedule	4/27/2017	Accepted by PMOS.

Schedule deviation	6/13/2017	Baseline initial ballot of 7/5/2017 moved to 9/7/2017 due addressing comments and scope of SAR. Schedule accounts for SC not meeting in August.
Schedule Adjustment	8/10/2017	No adjustment required 2013-03, 2015-09, and 2016-02 were staggered to spread postings out.

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	Responding to Comment
Comments	The SDT will be meeting with the 2015-9 SOL SDT on November 6-8 to align the CIP-002 standard with the SOL work.

Home

Deliverable	Address TO Control Centers Performing Transmission Operator (TOP) Obligations.
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, High
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Jordan Mallory
PMOS Liaison	Ken Lanehome, Ash Mayfield, and Kirk Rosener
Affected Standards	CIP-002-5.1a
Last Updated	11/14/2018

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

CP1 - Comment Period 1	3/14/2017	4/11/2017					Added to schedule, reduced period - SDT needed feedback
CP2 - Comment Period 2	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	12/5/2017	1/18/2018	3/31/2017	5/14/2017	(249)		
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							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/25/2019	2/15/2018	10/17/2017	10/27/2017	(465)		
PTB - Present to BOT	2/6/2019	2/8/2019	11/7/2017	11/9/2017	(456)		
Filing - Filing with Regulators	4/1/2019	4/4/2019	12/28/2017	12/31/2017	(459)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Archived comments	6/10/2016	Order 822 was issued on January 21, 2016. The SC authorized posting the SAR and to request nominations for additional team members at March 9, 2016 meeting. The SAR posting ended April 21, 2016 and the SDT is reviewing the comments received. A CIP Technical Conference was held on April 19, 2016 in Atlanta. Seven additional members were appointed to the SDT at the April 20, 2016 SC meeting. Initial SDT meeting May 24-26, 2016 in Atlanta.
Added CIP Schedule for approval	7/20/2016	Update SC that schedule was approved by SDT, SDT leadership, developer, and PMOS Liaison.

Liaison Change	3/15/2017	Updated B. Murpy and A. Gallow to K. Lanehome and A. Mayfield
Developer Change	4/1/2017	Replaced Al McMeekin with Mat Bunch and Katherine Street.
Schedule Adjustment	8/10/2017	The original 5/15/2017 planned posting was accepted for 9/18 to stagger 2013-03, 2015-09,
Schedule Adjustment	8/25/2017	The posting was advanced due to 2015-09 (SOL) being moved from its 9/12 posting to 9/30.
Developer Change	2/14/2018	Replaced Katherine Street with Jordan Mallory
SC Action	6/13/2018	The SC accepted the SAR to address recommended revisions to CIP-002 provided by Project
Developer Change	6/13/2018	Mat Bunch was removed from the project.

Project	**2016-02**	**Home**
Project Name	Modifications to CIP Standards	
Status	Posted	
Comments	The SDT will be posting for a 45-day informal comment period on November 2 through December 18, 2018.	
Deliverable	Address all remaining V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), Obligations, Virtualization, and CIP Exceptional Circumstances.	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, High	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Jordan Mallory	
PMOS Liaison	Ken Lanehome, Ash Mayfield, and Kirk Rosener	
Affected Standards	CIP-005, CIP-007 and CIP-010	
Last Updated	11/14/2018	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review	10/20/2016	10/30/2016	10/20/2016	10/30/2016			
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2	***11/2/2018***	***12/18/2018***					3rd Informal posting

CP1 - Comment Period 1	3/14/2017	4/11/2017	3/14/2017	4/11/2017			
CP2 - Comment Period 2	10/6/2017	11/2/2017					Unplanned
CIB - Com/Ballot 1 (Initial)	9/13/2018	10/27/2018	9/13/2018	10/29/2018			
CAB - Com/Add Ballot 2	12/14/2018	1/28/2019	12/14/2018	1/28/2019			
CAB - Com/Add Ballot 3	3/5/2019	4/19/2019	3/2/2019	4/19/2019	(3)		
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	5/13/2019	5/23/2019	5/13/2019	5/23/2019			
PTB - Present to BOT	8/6/2019	8/8/2019					
Filing - Filing with Regulators	9/1/2019	9/4/2019					
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Segmented project	8/8/2017	This fourth segment of the project was made to address all remaining V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), Obligations, Virtualization, and CIP Exceptional Circumstances.
Assign PMOS Liaison	10/12/2017	Assigned Kirk Rosener to support Ken Lanehome and Ash Mayfield.
Developer Change	2/14/2018	Replaced Katherine Street with Jordan Mallory
Developer Change	6/13/2018	Mat Bunch was removed from the project.
Accept baseline schedule	9/13/2018	PMOS accepted the baseline following appointment of additional members in July 2018.
Delay	9/1/2018	Project delayed from August 2018 to January 2019 (tentatively) for 2018-02, CIP-008 to finish.

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	Responding to Comment
Comments	The CIP-003 standard was posted for comment and initial ballot through October 9, 2018. The ballot passed at 90.06%. The drafting team will meet through November and December to respond to comments and to determine next steps.
Deliverable	CIP-003-8 (FERC Order No. 843 Malicious Code Example Directive)
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, High
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Jordan Mallory
PMOS Liaison	Ken Lanehome, Ash Mayfield, and Kirk Rosener
Affected Standards	CIP-003-7
Last Updated	11/14/2018

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							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							

CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	8/23/2018	10/9/2018	8/23/2018	10/7/2018			
CAB - Com/Add Ballot 2	***11/22/2018***	***1/6/2019***	***11/22/2018***	***1/6/2019***			
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/25/2019	2/4/2019	1/25/2019	2/4/2019			
PTB - Present to BOT	2/6/2019	2/8/2019	2/6/2019	2/8/2019			
Filing - Filing with Regulators	3/6/2019	3/8/2019	3/6/2019	3/8/2019			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Segmented project	7/30/2018	CIP-003 for malicous code was segmented into its own tracking worksheet.
Accept Baseline	10/31/2018	PMOS accepted the baseline provided by the SDT.

Project	**2017-01**	**Home**
Project Name	Modifications to BAL-003-1.1	
Status	Pending SC Action	
Comments	The SDT held a conference call on October 19 to finalize documentation for authorization of a formal posting for comment and initial ballot to the SC at its November meeting.	
Deliverable	BAL-003-2	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, Medium	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Laura Anderson	
PMOS Liaison	Amy Casuscelli & Linda Lynch	
Affected Standards	BAL-003-1.1	
Last Updated	11/14/2018	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	6/19/2017	7/3/2017	6/19/2017	7/3/2017			
Nominations - DT	7/27/2017	8/9/2017	7/27/2017	8/9/2017			Supplemental Nominations
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/19/2017	7/18/2017	6/19/2017	7/18/2017			By NERC RS
SP2 - SAR/PR/WP Posting 2	11/2/2017	12/1/2017	11/2/2017	12/1/2017			By NWPP FRSG
CP1 - Comment Period 1	9/6/2018	9/20/2018					Unscheduled posting

CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	**11/26/2018**	**1/9/2019**	***11/6/2018***	***1/9/2019***	(20)		
CAB - Com/Add Ballot 2	2/18/2019	4/3/2019	2/18/2019	4/3/2019			
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	4/16/2019	4/25/2019	4/16/2019	4/25/2019			
PTB - Present to BOT	5/9/2019	5/11/2019	5/9/2019	5/11/2019			
Filing - Filing with Regulators	6/9/2019	6/16/2019	6/9/2019	6/16/2019			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Amy Casuscelli accepted appointment as PMOS liaison.
Assign PMOS Liaison	10/12/2017	Add Linda Lynch to support Amy Casuscelli.
Updated Standard Number	6/6/2018	Changed standard from BAL-003-1 to BAL-003-1.1.
Accept baseline	7/18/2018	PMOS accepted baseline project schedule.

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)	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Al McMeekin	
PMOS Liaison	Mark Pratt	
Affected Standards	FAC-008-3	
Last Updated	11/14/2018	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	5/10/2017	5/23/2017	5/10/2017	5/23/2017			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	10/30/2017	12/13/2017	10/30/2017	12/13/2017			
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							

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

PTS Change Control

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

Project	**2017-04**	**Home**
Project Name	Periodic Review of Interchange Scheduling and Coordination Standards	
Status	On Hold	
Comments	The response to comments are complete. Comments were in favor of the recommendations being made by the team which is to retire one standard and drop terms which are unclear in the standards. Periodic Review of subset INT Standards will provide the Standards Efficiency Review Team (SER) (Gary Nolan is the contact person) with the initial recommendations of the INT periodic review team, as well as all associated documents this week. No future meetings or postings expected for now. Project 2017-04 will then be placed on hold pending Standards Efficiency Review team recommendations/findings. No recommendations have been made to the Standards Committee.	
Deliverable	PR Recommendations	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low (was Medium previously)	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Laura Anderson	
PMOS Liaison	Charles Yeung	
Affected Standards	INT-004, INT-006, INT-009, and INT-010	
Last Updated	11/14/2018	

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

PTS Change Control

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

Project	**2017-05**	**Home**
Project Name	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)	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Mat Bunch	
PMOS Liaison	Amy Casuscelli and Colby Bellville	
Affected Standards	NUC-001-3	
Last Updated	11/14/2018	

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)		
CP2 - Comment Period 2							

CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

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

Project	**2017-07**	**Home**
Project Name	Stds Alignment with Registration	
Status	On Hold	
Comments	The project is on a temporary hold for coordination with other projects (such as Standards Efficiency Review and CIP) because many of the requirements that address these functional entities, are being considered for retirement. 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). This project is not addressing a reliability issue and has a low priority in the RSDP; therefore, the project is in a holding pattern in the interim.	
Deliverable	Standards with PSE, IA, or LSE	
Deadline		
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low	
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	Standards with PSE, IA, or LSE	
Last Updated	11/14/2018	

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)		
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)			9/17/2018	11/1/2018			
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot			***12/4/2018***	**********			
PTB - Present to BOT			2/5/2019	2/8/2019			
Filing - Filing with Regulators			3/7/2019	3/10/2019			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Assign PMOS Liaison	7/27/2017	Mike Brytowski accepted appointment as PMOS liaison.
SC Action	6/13/2018	SC appoint drafting team as recommended by NERC staff.
Accept Baseline	9/13/2018	PMOS accepted based line as presented to the members.
Schedule adjustment	10/31/2018	The PMOS removed the "projected schedule" as it was inaccurate and misleading.

Project	**2018-01**	**Home**
Project Name	Canadian-specific Revisions to TPL-007-2	
Status	Posted	
Comments	The team met in September to respond to stakeholder comments. The standard is posted for a 45-day initial comment period and initial ballot through November 15, 2018.	
Deliverable	TPL-007-3	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 10, Medium	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Mat Bunch	
PMOS Liaison	Charles Yeung	
Affected Standards	TPL-007-2	
Last Updated	11/14/2018	

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	3/30/2018	4/19/2018					
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	3/30/2018	4/30/2018	3/30/2018	4/30/2018			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	8/10/2018	9/6/2018	8/10/2018	9/9/2018			
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	10/2/2018	11/15/2018	10/5/2018	11/19/2018	3		
CAB - Com/Add Ballot 2	12/6/2018	1/20/2019	12/6/2018	1/20/2019			
CAB - Com/Add Ballot 3							

CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/24/2019	2/3/2019	1/24/2019	2/3/2019			
PTB - Present to BOT	2/7/2019	2/9/2019	2/7/2019	2/9/2019			
Filing - Filing with Regulators	3/7/2019	3/9/2019	3/7/2019	3/9/2019			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Assign PMOS Liaison	4/25/2018	C. Yeung acccept to follow project.
Accept baseline schedule	9/13/2018	PMOS accepted the baseline schedule as presented to the members.
Corrected BOT Date	10/3/2018	Baseline incorrectly listed BOT delivery for May 2019 and it should have been Feb 2019.

Project	**2018-02**	**Home**
Project Name	Modifications to CIP-008 Cyber Security Incident Reporting	
Status	Posted	
Comments	The abbreviated comment period and initial ballot ended on October 22, 2018. The ballot failed considerably at 20.02%. NOTE: The second posting is scheduled for November 14, 2018. The comment period and ballot period considerably shorter to be able to work toward the January 2019 deadline.	
Deliverable	CIP-008-6	
Deadline	1/19/2019	
Priority in RSDP, click to see applicable Footnote	Footnote 10, High	
P81 Req (2013)	N/A	
Number of Directives	Order No. 848 (1 Directive, 4 elements)	
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 & Amy Casuscelli	
Affected Standards	CIP-008-5	
Last Updated	11/14/2018	

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	8/10/2018	8/29/2018	8/10/2018	8/30/2018			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	8/10/2018	9/10/2018	8/10/2018	9/9/2018			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	10/3/2018	10/22/2018	10/4/2018	10/24/2018	1		

CAB - Com/Add Ballot 2	11/14/2018	11/29/2018	11/14/2018	11/29/2018			
CAB - Com/Add Ballot 3	12/8/2018	12/23/2018					
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/14/2019	1/19/2019	1/14/2019	1/19/2019			
PTB - Present to BOT	2/6/2019	2/8/2019	2/6/2019	2/8/2019			
Filing - Filing with Regulators	2/9/2019	2/10/2019					
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
SC Action	8/9/2018	SCEC authorized posting of the SAR and solicitation of nominations.
Project added to PTS	8/10/2018	Added project for tracking by PMOS.
Assign PMOS Liaison	9/13/2018	PMOS appointed Colby Belleville and Amy Casuscelli to the project.
SC Action	10/2/2018	SCEC authorized posting with shortened (waiver) posting periods.
Accept Baseline	10/31/2018	PMOS accepted the baseline schedule (periods are compressed as approved by SC).

Home

Project	**2018-03**
Project Name	Standards Efficiency Review - Phase I
Status	Nominations
Comments	
Deliverable	Retirements Only
Deadline	
Priority in RSDP, click to see applicable Footnote	N/A
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 & Michael Brytowski
Affected Standards	Various
Last Updated	11/14/2018

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	8/28/2018	9/17/2018					
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	8/28/2018	9/26/2018					
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
New Project	8/22/2018	SC authorized project.

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

Note 7	**2016-2018 RSDP** The following projects are planned to continue from 2015 along with any 2015 projects that are planned to be completed in that year but need additional time. As in the 2015–2017 RSDP, the approach to prioritizing Reliability Standards projects in this RSDP addressed how Reliability Standard family priorities are applied to individual projects and outstanding work. Specific elements included: (1) RISC Category Rankings; (2) regulatory directives; (3) regulatory deadlines; (4) Reliability Standard requirement candidates for retirement; (5) the IERP content and quality assessments; and (6) additional considerations (fill-in-the-blank status and five-year assessment commitments). The prioritization gave primary consideration to RISC category rankings, regulatory directives, and regulatory deadlines. Based on the application of these elements, this section prioritizes each Reliability Standard project as high, medium, low, or pending technical committee input.
Note 8	**2017-2019 RSDP** The approach to prioritizing Reliability Standards projects in this RSDP is consistent with previous RSDPs. Specific elements include: (1) RISC Category Rankings; (2) regulatory directives and deadlines; (3) Reliability Standard requirements recommended for retirement; (4) the IERP content and quality assessments; and (5) additional considerations (fill-in-the-blank status and five-year assessment commitments). The prioritization considers RISC category rankings, regulatory directives, and regulatory deadlines. Based on the application of these elements, this section prioritizes each Reliability Standard project as high, medium, low, or pending technical committee input.
Note 9	2018-2020 RSDP
Note 10	2019-2021 RSDP (Draft)

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 standards were posted for formal comment through October 17, 2018 (extended from the 9th). The SDT plans to meet with the CIP SDT in November 6-8 to coordinate alignment with CIP-002.	CIP-014-3, FAC-003-5, 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	N/A	N/A	Latrice Harkness & Darrel Richardson	Ken Lanehome	CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-1 and the retirement of FAC-010	10/31/2018
2015-09	Establish and Communicate System Operating Limits	On Hold	The IROL portion of the project has been placed on hold pending additional information.	IROL Stds.	N/A	Medium	N/A	N/A	N/A	N/A	Al McMeekin	TBD - On Hold	TBD - On Hold	10/30/2018
2015-10	Single Points of Failure TPL-001	Pending Board Adoption	The standard was posted through September 22, 2018 and was approved by industry with a 66.67% vote. The standard will go to the NERC Board of Trustees for adoption in November 2018.	TPL-001-5	N/A	Footnote 8, High	N/A	2 directives at P40 & P89 (Click this link for FERC Order)	N/A	N/A	Latrice Harkness	Mark Pratt	TPL-001-4	10/30/2018
2016-02	Modifications to CIP Standards	Responding to Comment	The SDT will be meeting with the 2015-9 SOL SDT on November 6-8 to align the CIP-002 standard with the SOL work.	Address TO Control Centers Performing Transmission Operator (TOP) Obligations.	N/A	Footnote 8, High	N/A	N/A	N/A	N/A	Jordan Mallory	Ken Lanehome, Ash Mayfield, and Kirk Rosener	CIP-002-5.1a	10/30/2018
2016-02	Modifications to CIP Standards	Posted	The SDT will be posting for a 45-day informal comment period on November 2 through December 18, 2018.	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.	N/A	Footnote 8, High	N/A	N/A	N/A	N/A	Jordan Mallory	Ken Lanehome, Ash Mayfield, and Kirk Rosener	CIP-005, CIP-007 and CIP-010	11/2/2018
2016-02	Modifications to CIP Standards	Responding to Comment	The CIP-003 standard was posted for comment and initial ballot through October 9, 2018. The ballot passed at 90.06%. The drafting team will meet through November and December to respond to comments and to determine next steps.	CIP-003-8 (FERC Order No. 843 Malicious Code Example Directive)	N/A	Footnote 8, High	N/A	N/A	N/A	N/A	Jordan Mallory	Ken Lanehome, Ash Mayfield, and Kirk Rosener	CIP-003-7	11/2/2018
2017-01	Modifications to BAL-003-1.1	Responding to Comment	The standard was informally posted through September 20, 2018 along with supporting documents. The SDT met the week of September 24, 2018 at SPP in Little Rock, AR to review comments and to determine next steps.	BAL-003-2	N/A	Footnote 8, Medium	N/A	N/A	N/A	N/A	Laura Anderson	Amy Casuscelli & Linda Lynch	BAL-003-1.1	10/30/2018
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	N/A	N/A	Al McMeekin	Mark Pratt	FAC-008-3	10/30/2018

2017-04	Periodic Review of Interchange Scheduling and Coordination Standards	On Hold	The response to comments are complete. Comments were in favor of the recommendations being made by the team which is to retire one standard and drop terms which are unclear in the standards. Periodic Review of subset INT Standards will provide the Standards Efficiency Review Team (SER) (Gary Nolan is the contact person) with the initial recommendations of the INT periodic review team, as well as all associated documents this week. No future meetings or postings expected for now. Project 2017-04 will then be placed on hold pending Standards Efficiency Review team recommendations/findings. No recommendations have been made to the Standards Committee.	PR Recommendations	N/A	Footnote 9, Low (was Medium previously)	N/A	N/A	N/A	N/A	Laura Anderson	Charles Yeung	INT-004, INT-006, INT-009, and INT-010	10/30/2018
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	N/A	N/A	Mat Bunch	Amy Casuscelli and Colby Bellville	NUC-001-3	10/30/2018
2017-07	Stds Alignment with Registration	On Hold	The project is on a temporary hold for coordination with other projects (such as Standards Efficiency Review and CIP) because many of the requirements that address these functional entities, are being considered for retirement. 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). This project is not addressing a reliability issue and has a low priority in the RSDP; therefore, the project is in a holding pattern in the interim.	Standards with PSE, IA, or LSE		Footnote 9, Low	N/A	N/A	N/A	N/A	Laura Anderson	Mike Brytowski	Standards with PSE, IA, or LSE	10/31/2018
2018-01	Canadian-specific Revisions to TPL-007-2	Posted	The team met in September to respond to stakeholder comments. The standard is posted for a 45-day initial comment period and initial ballot through November 15, 2018.	TPL-007-3	N/A	Footnote 10, Medium	N/A	N/A	N/A	N/A	Mat Bunch	Charles Yeung	TPL-007-2	10/30/2018
2018-02	Modifications to CIP-008 Cyber Security Incident Reporting	Responding to Comment	The abbreviated comment period and initial ballot ended on October 22, 2018. The ballot failed considerably at 20.02%. NOTE: The comment period and ballot period considerably shorter to be able to work toward the January 2019 deadline.	CIP-008-6	1/19/2019	Footnote 10, High	N/A	Order No. 848 (1 Directive, 4 elements)	N/A	N/A	Alison Oswald	Colby Bellville & Amy Casuscelli	CIP-008-5	10/30/2018
Standards Efficiency Review	Phase 1	SAR	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.	Retirement of various requirements	N/A	N/A, not priorized in the RSDP	(Ops Plan) Amy Casuscelli & Charles Yeung	(RT Ops) Mike Brytowski	(LT Plan) Linda Lynch	N/A	Chris Larson	Mark Pratt & Michael Brytowski	See SAR (too many to list)	11/2/2018

Project	**Standards Efficiency Review**	**Home**
Project Name	Phase 1	
Status	SAR	
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	Retirement of various requirements	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	N/A, not priorized in the RSDP	
Operations Planning Subteam	(Ops Plan) Amy Casuscelli & Charles Yeung	
Real-time Operations Subteam	(RT Ops) Mike Brytowski	
Long-term Planning Subteam	(LT Plan) Linda Lynch	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Chris Larson	
Primary PMOS Liaison(s)	Mark Pratt & Michael Brytowski	
Affected Standards	See SAR (too many to list)	
Last Updated	11/2/2018	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	11/14/2017	11/30/2017					
Nominations - DT	8/28/2018	9/17/2018					
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	8/28/2018	9/26/2018					
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	6/7/2018	7/10/2018					
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							

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

PTS Change Control

Reason for Update	Date	Notes

Project	**2015-09**
Project Name	Establish and Communicate System Operating Limits
Status	Working to Additional Ballot
Comments	The standards were posted for formal comment through October 17, 2018 (extended from the 9th). The SDT plans to meet with the CIP SDT in November 6-8 to coordinate alignment with CIP-002.
Deliverable	CIP-014-3, FAC-003-5, 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
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	CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-1 and the retirement of FAC-010
Last Updated	10/31/2018

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review			4/4/2016	4/14/2016		Not needed	
SP1 - SAR/PR/WP Posting 1	8/20/2015	9/21/2015	8/20/2015	9/21/2015			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	7/14/2016	8/12/2016	7/8/2016	8/7/2016	(6)		
CP2 - Comment Period 2							

CIB - Com/Ballot 1 (Initial)	9/29/2017	11/13/2017	9/22/2017	11/5/2017	(7)		Posting date changed see notes 8/10 and 8/25.
CAB - Com/Add Ballot 2	4/9/2018	5/24/2018	1/17/2018	3/2/2018	(82)		
CAB - Com/Add Ballot 3	8/24/2018	10/17/2018					not in original baseline
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	11/16/2018	11/26/2018	4/2/2018	4/12/2018	(228)		
PTB - Present to BOT	11/15/2018	11/17/2018	5/1/2018	5/3/2018	(198)		
Filing - Filing with Regulators	12/15/2018	12/18/2018	6/1/2018	6/4/2018	(197)		
PT - Post Approval Training							

PTS Change Control

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

Project	**2015-09**	**Home**
Project Name	Establish and Communicate System Operating Limits	
Status	On Hold	
Comments	The IROL portion of the project has been placed on hold pending additional information.	
Deliverable	IROL Stds.	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Medium	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Al McMeekin	
PMOS Liaison	TBD - On Hold	
Affected Standards	TBD - On Hold	
Last Updated	10/30/2018	

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							
CAB - Com/Add Ballot 5							

FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Bifurcate Project	3/31/2017	Split the IRO portion into this section for tracking.
Worksheet created	8/10/2017	PMOS suggested visibility on this IROL portion.
Worksheet made visible	4/25/2018	PMOS requested that the IRO portion be tracked going forward.

Project	**2015-10**
Project Name	Single Points of Failure TPL-001
Status	Pending Board Adoption
Comments	The standard was posted through September 22, 2018 and was approved by industry with a 66.67% vote. The standard will go to the NERC Board of Trustees for adoption in November 2018.

Home

Deliverable	TPL-001-5
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, High
P81 Req (2013)	N/A
Number of Directives	2 directives at P40 & P89 (Click this link for FERC Order)
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Latrice Harkness
PMOS Liaison	Mark Pratt
Affected Standards	TPL-001-4
Last Updated	10/30/2018

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	11/12/2015	12/1/2015	1/18/2016	2/1/2016	67		
Nominations - DT	7/22/2016	8/5/2016	7/25/2016	8/8/2016	3		
QR - Quality Review			5/30/2016	6/9/2016			
SP1 - SAR/PR/WP Posting 1	11/12/2015	12/17/2015	11/12/2015	12/17/2015			
SP2 - SAR/PR/WP Posting 2	5/26/2016	6/24/2016	6/15/2016	7/15/2016	20	Expanded Scope	

CP1 - Comment Period 1	4/25/2017	5/24/2017	4/25/2017	5/24/2017		Other	Team added informal comment period
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/8/2017	10/23/2017	7/5/2017	8/18/2017	(65)		Held at 9/7 to stagger 2013-03 and 2015-09.
CAB - Com/Add Ballot 2	2/23/2018	4/23/2018	10/18/2017	12/1/2017	(128)		Period extended from 4/9 to 4/23 due to changes
CAB - Com/Add Ballot 3	7/30/2018	9/14/2018					Additional period
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	10/11/2018	10/22/2018	1/8/2018	1/17/2018	(276)		
PTB - Present to BOT	11/6/2018	11/8/2018	2/1/2018	2/3/2018	(278)		
Filing - Filing with Regulators	12/6/2018	12/9/2018	3/1/2018	3/4/2018	(280)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Expansion of Scope	6/14/2016	FERC directives added (P40 & P89) additional scoping in addition to industry comments following the second SAR posting. The MOD references are being updated due to some retiring
Developer change	1/13/2017	Transition from Lacey Ourso to Soo Jin Kim until a new developer is assigned.
Accept Schedule	4/27/2017	Accepted by PMOS.

Schedule deviation	6/13/2017	Baseline initial ballot of 7/5/2017 moved to 9/7/2017 due addressing comments and scope of SAR. Schedule accounts for SC not meeting in August.
Schedule Adjustment	8/10/2017	No adjustment required 2013-03, 2015-09, and 2016-02 were staggered to spread postings out.

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	Responding to Comment
Comments	The SDT will be meeting with the 2015-9 SOL SDT on November 6-8 to align the CIP-002 standard with the SOL work.

Home

Deliverable	Address TO Control Centers Performing Transmission Operator (TOP) Obligations.
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, High
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Jordan Mallory
PMOS Liaison	Ken Lanehome, Ash Mayfield, and Kirk Rosener
Affected Standards	CIP-002-5.1a
Last Updated	10/30/2018

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

CP1 - Comment Period 1	3/14/2017	4/11/2017					Added to schedule, reduced period - SDT needed feedback
CP2 - Comment Period 2	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	12/5/2017	1/18/2018	3/31/2017	5/14/2017	(249)		
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							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/25/2019	2/15/2018	10/17/2017	10/27/2017	(465)		
PTB - Present to BOT	2/6/2019	2/8/2019	11/7/2017	11/9/2017	(456)		
Filing - Filing with Regulators	4/1/2019	4/4/2019	12/28/2017	12/31/2017	(459)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Archived comments	6/10/2016	Order 822 was issued on January 21, 2016. The SC authorized posting the SAR and to request nominations for additional team members at March 9, 2016 meeting. The SAR posting ended April 21, 2016 and the SDT is reviewing the comments received. A CIP Technical Conference was held on April 19, 2016 in Atlanta. Seven additional members were appointed to the SDT at the April 20, 2016 SC meeting. Initial SDT meeting May 24-26, 2016 in Atlanta.
Added CIP Schedule for approval	7/20/2016	Update SC that schedule was approved by SDT, SDT leadership, developer, and PMOS Liaison.

Liaison Change	3/15/2017	Updated B. Murpy and A. Gallow to K. Lanehome and A. Mayfield
Developer Change	4/1/2017	Replaced Al McMeekin with Mat Bunch and Katherine Street.
Schedule Adjustment	8/10/2017	The original 5/15/2017 planned posting was accepted for 9/18 to stagger 2013-03, 2015-09,
Schedule Adjustment	8/25/2017	The posting was advanced due to 2015-09 (SOL) being moved from its 9/12 posting to 9/30.
Developer Change	2/14/2018	Replaced Katherine Street with Jordan Mallory
SC Action	6/13/2018	The SC accepted the SAR to address recommended revisions to CIP-002 provided by Project
Developer Change	6/13/2018	Mat Bunch was removed from the project.

Project	**2016-02**	**Home**
Project Name	Modifications to CIP Standards	
Status	Posted	
Comments	The SDT will be posting for a 45-day informal comment period on November 2 through December 18, 2018.	
Deliverable	Address all remaining V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), Obligations, Virtualization, and CIP Exceptional Circumstances.	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, High	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Jordan Mallory	
PMOS Liaison	Ken Lanehome, Ash Mayfield, and Kirk Rosener	
Affected Standards	CIP-005, CIP-007 and CIP-010	
Last Updated	11/2/2018	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review	10/20/2016	10/30/2016	10/20/2016	10/30/2016			
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2	***11/2/2018***	***12/18/2018***					3rd Informal posting

CP1 - Comment Period 1	3/14/2017	4/11/2017	3/14/2017	4/11/2017			
CP2 - Comment Period 2	10/6/2017	11/2/2017					Unplanned
CIB - Com/Ballot 1 (Initial)	9/13/2018	10/27/2018	9/13/2018	10/29/2018			
CAB - Com/Add Ballot 2	12/14/2018	1/28/2019	12/14/2018	1/28/2019			
CAB - Com/Add Ballot 3	3/5/2019	4/19/2019	3/2/2019	4/19/2019	(3)		
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	5/13/2019	5/23/2019	5/13/2019	5/23/2019			
PTB - Present to BOT	8/6/2019	8/8/2019					
Filing - Filing with Regulators	9/1/2019	9/4/2019					
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Segmented project	8/8/2017	This fourth segment of the project was made to address all remaining V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), Obligations, Virtualization, and CIP Exceptional Circumstances.
Assign PMOS Liaison	10/12/2017	Assigned Kirk Rosener to support Ken Lanehome and Ash Mayfield.
Developer Change	2/14/2018	Replaced Katherine Street with Jordan Mallory
Developer Change	6/13/2018	Mat Bunch was removed from the project.
Accept baseline schedule	9/13/2018	PMOS accepted the baseline following appointment of additional members in July 2018.
Delay	9/1/2018	Project delayed from August 2018 to January 2019 (tentatively) for 2018-02, CIP-008 to finish.

Project	**2016-02**	**Home**
Project Name	Modifications to CIP Standards	
Status	Responding to Comment	
Comments	The CIP-003 standard was posted for comment and initial ballot through October 9, 2018. The ballot passed at 90.06%. The drafting team will meet through November and December to respond to comments and to determine next steps.	
Deliverable	CIP-003-8 (FERC Order No. 843 Malicious Code Example Directive)	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, High	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Jordan Mallory	
PMOS Liaison	Ken Lanehome, Ash Mayfield, and Kirk Rosener	
Affected Standards	CIP-003-7	
Last Updated	11/2/2018	

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)	8/23/2018	10/9/2018	8/23/2018	10/7/2018			
CAB - Com/Add Ballot 2	11/22/2018	1/6/2019	11/22/2018	1/6/2019			
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/25/2019	2/4/2019	1/25/2019	2/4/2019			
PTB - Present to BOT	2/6/2019	2/8/2019	2/6/2019	2/8/2019			
Filing - Filing with Regulators	3/6/2019	3/8/2019	3/6/2019	3/8/2019			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Segmented project	7/30/2018	CIP-003 for malicous code was segmented into its own tracking worksheet.
Accept Baseline	TBD	PMOS Accepted the baseline provided by the SDT.

Project	**2017-01**	**Home**
Project Name	Modifications to BAL-003-1.1	
Status	Responding to Comment	
Comments	The standard was informally posted through September 20, 2018 along with supporting documents. The SDT met the week of September 24, 2018 at SPP in Little Rock, AR to review comments and to determine next steps.	
Deliverable	BAL-003-2	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, Medium	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Laura Anderson	
PMOS Liaison	Amy Casuscelli & Linda Lynch	
Affected Standards	BAL-003-1.1	
Last Updated	10/30/2018	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	6/19/2017	7/3/2017	6/19/2017	7/3/2017			
Nominations - DT	7/27/2017	8/9/2017	7/27/2017	8/9/2017			Supplemental Nominations
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/19/2017	7/18/2017	6/19/2017	7/18/2017			By NERC RS
SP2 - SAR/PR/WP Posting 2	11/2/2017	12/1/2017	11/2/2017	12/1/2017			By NWPP FRSG
CP1 - Comment Period 1	9/6/2018	9/20/2018					Unscheduled posting

CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	**11/6/2018**	**1/9/2019**	***11/6/2018***	***1/9/2019***			
CAB - Com/Add Ballot 2	2/18/2019	4/3/2019	2/18/2019	4/3/2019			
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	4/16/2019	4/25/2019	4/16/2019	4/25/2019			
PTB - Present to BOT	5/9/2019	5/11/2019	5/9/2019	5/11/2019			
Filing - Filing with Regulators	6/9/2019	6/16/2019	6/9/2019	6/16/2019			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Amy Casuscelli accepted appointment as PMOS liaison.
Assign PMOS Liaison	10/12/2017	Add Linda Lynch to support Amy Casuscelli.
Updated Standard Number	6/6/2018	Changed standard from BAL-003-1 to BAL-003-1.1.
Accept baseline	7/18/2018	PMOS accepted baseline project schedule.

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)	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Al McMeekin	
PMOS Liaison	Mark Pratt	
Affected Standards	FAC-008-3	
Last Updated	10/30/2018	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	5/10/2017	5/23/2017	5/10/2017	5/23/2017			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	10/30/2017	12/13/2017	10/30/2017	12/13/2017			
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							

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

PTS Change Control

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

Project	**2017-04**	**Home**
Project Name	Periodic Review of Interchange Scheduling and Coordination Standards	
Status	On Hold	
Comments	The response to comments are complete. Comments were in favor of the recommendations being made by the team which is to retire one standard and drop terms which are unclear in the standards. Periodic Review of subset INT Standards will provide the Standards Efficiency Review Team (SER) (Gary Nolan is the contact person) with the initial recommendations of the INT periodic review team, as well as all associated documents this week. No future meetings or postings expected for now. Project 2017-04 will then be placed on hold pending Standards Efficiency Review team recommendations/findings. No recommendations have been made to the Standards Committee.	
Deliverable	PR Recommendations	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low (was Medium previously)	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Laura Anderson	
PMOS Liaison	Charles Yeung	
Affected Standards	INT-004, INT-006, INT-009, and INT-010	
Last Updated	10/30/2018	

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

PTS Change Control

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

Project	**2017-05**	**Home**
Project Name	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)	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Mat Bunch	
PMOS Liaison	Amy Casuscelli and Colby Bellville	
Affected Standards	NUC-001-3	
Last Updated	10/30/2018	

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)		
CP2 - Comment Period 2							

CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

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

Project	**2017-07**	**Home**
Project Name	Stds Alignment with Registration	
Status	On Hold	
Comments	The project is on a temporary hold for coordination with other projects (such as Standards Efficiency Review and CIP) because many of the requirements that address these functional entities, are being considered for retirement. 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). This project is not addressing a reliability issue and has a low priority in the RSDP; therefore, the project is in a holding pattern in the interim.	
Deliverable	Standards with PSE, IA, or LSE	
Deadline		
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low	
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	Standards with PSE, IA, or LSE	
Last Updated	10/31/2018	

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)		
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)			9/17/2018	11/1/2018			
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot			12/4/2018	12/14/2018			
PTB - Present to BOT			2/5/2019	2/8/2019			
Filing - Filing with Regulators			3/7/2019	3/10/2019			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Assign PMOS Liaison	7/27/2017	Mike Brytowski accepted appointment as PMOS liaison.
SC Action	6/13/2018	SC appoint drafting team as recommended by NERC staff.
Accept Baseline	9/13/2018	PMOS accepted based line as presented to the members.

Project	**2018-01**	**Home**
Project Name	Canadian-specific Revisions to TPL-007-2	
Status	Posted	
Comments	The team met in September to respond to stakeholder comments. The standard is posted for a 45-day initial comment period and initial ballot through November 15, 2018.	
Deliverable	TPL-007-3	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 10, Medium	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Mat Bunch	
PMOS Liaison	Charles Yeung	
Affected Standards	TPL-007-2	
Last Updated	10/30/2018	

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	3/30/2018	4/19/2018					
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	3/30/2018	4/30/2018	3/30/2018	4/30/2018			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	8/10/2018	9/6/2018	8/10/2018	9/9/2018			
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	***10/2/2018***	***11/15/2018***	***10/5/2018***	***11/19/2018***	3		
CAB - Com/Add Ballot 2	12/6/2018	1/20/2019	12/6/2018	1/20/2019			
CAB - Com/Add Ballot 3							

CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/24/2019	2/3/2019	1/24/2019	2/3/2019			
PTB - Present to BOT	2/7/2019	2/9/2019	2/7/2019	2/9/2019			
Filing - Filing with Regulators	3/7/2019	3/9/2019	3/7/2019	3/9/2019			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Assign PMOS Liaison	4/25/2018	C. Yeung acccept to follow project.
Accept baseline schedule	9/13/2018	PMOS accepted the baseline schedule as presented to the members.
Corrected BOT Date	10/3/2018	Baseline incorrectly listed BOT delivery for May 2019 and it should have been Feb 2019.

Project	**2018-02**	**Home**
Project Name	Modifications to CIP-008 Cyber Security Incident Reporting	
Status	Responding to Comment	
Comments	The abbreviated comment period and initial ballot ended on October 22, 2018. The ballot failed considerably at 20.02%. NOTE: The comment period and ballot period considerably shorter to be able to work toward the January 2019 deadline.	

Deliverable	CIP-008-6
Deadline	1/19/2019
Priority in RSDP, click to see applicable Footnote	Footnote 10, High
P81 Req (2013)	N/A
Number of Directives	Order No. 848 (1 Directive, 4 elements)
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 & Amy Casuscelli
Affected Standards	CIP-008-5
Last Updated	10/30/2018

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	8/10/2018	8/29/2018	8/10/2018	8/30/2018			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	8/10/2018	9/10/2018	8/10/2018	9/9/2018			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	10/3/2018	10/22/2018	10/4/2018	10/24/2018	1		

CAB - Com/Add Ballot 2	11/14/2018	11/29/2018	11/14/2018	11/29/2018			
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/14/2019	1/19/2019	1/14/2019	1/19/2019			
PTB - Present to BOT	2/6/2019	2/8/2019	2/6/2019	2/8/2019			
Filing - Filing with Regulators	2/9/2019	2/10/2019					
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
SC Action	8/9/2018	SCEC authorized posting of the SAR and solicitation of nominations.
Project added to PTS	8/10/2018	Added project for tracking by PMOS.
Assign PMOS Liaison	9/13/2018	PMOS appointed Colby Belleville and Amy Casuscelli to the project.
SC Action	10/2/2018	SCEC authorized posting with shortened (waiver) posting periods.
Accept Baseline	10/31/2018	PMOS accepted the baseline schedule (periods are compressed as approved by SC).

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

Note 7	**2016-2018 RSDP** The following projects are planned to continue from 2015 along with any 2015 projects that are planned to be completed in that year but need additional time. As in the 2015–2017 RSDP, the approach to prioritizing Reliability Standards projects in this RSDP addressed how Reliability Standard family priorities are applied to individual projects and outstanding work. Specific elements included: (1) RISC Category Rankings; (2) regulatory directives; (3) regulatory deadlines; (4) Reliability Standard requirement candidates for retirement; (5) the IERP content and quality assessments; and (6) additional considerations (fill-in-the-blank status and five-year assessment commitments). The prioritization gave primary consideration to RISC category rankings, regulatory directives, and regulatory deadlines. Based on the application of these elements, this section prioritizes each Reliability Standard project as high, medium, low, or pending technical committee input.
Note 8	**2017-2019 RSDP** The approach to prioritizing Reliability Standards projects in this RSDP is consistent with previous RSDPs. Specific elements include: (1) RISC Category Rankings; (2) regulatory directives and deadlines; (3) Reliability Standard requirements recommended for retirement; (4) the IERP content and quality assessments; and (5) additional considerations (fill-in-the-blank status and five-year assessment commitments). The prioritization considers RISC category rankings, regulatory directives, and regulatory deadlines. Based on the application of these elements, this section prioritizes each Reliability Standard project as high, medium, low, or pending technical committee input.
Note 9	2018-2020 RSDP
Note 10	2019-2021 RSDP (Draft)

RSC Meeting #18-5, 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	By end of the year	Pending

DRAFT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards, Compliance, and Enforcement Bulletin

December 3–9, 2018

INSIDE THIS EDITION

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

ACTIVE STANDARDS POSTINGS

Current and Upcoming Ballots (ballot periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
NEW Project 2018-01 – Canadian-specific Revisions to TPL-007-2	Final Ballots	11/29/18	12/10/18
Join Ballot Pools (ballot pool windows close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
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Posted for Comment			
Project	**Action**	**Start Date**	**End Date**
Project 2016-02 – Modifications to CIP Standards | Virtualization Updates for CIP-004, CIP-006, CIP-007, CIP-010, and Associated Definitions	Comment Period	11/02/18	12/18/18

OTHER ACTIVE COMMENT PERIODS

Posted for Comment			
Posting	**Action**	**Start Date**	**End Date**
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STANDARDS NEWS

NEW Resources Posted

NERC has posted the streaming webinar and slide presentation for the November 15, 2018 Project 2016-02 – Modifications to CIP Standards Virtualization and Other Technology Innovations webinar.

Quick Links

- Register in the SBS
- Projected Standards Posting Schedule
- Project Tracking Spreadsheet
- Standards Related Questions – Single Portal
- 2017–2019 Reliability Standards Development Plan
- Quality Review Application
- One-Stop Shop (Status, Purpose, Implementation Plans, FERC Orders, RSAWs)

GENERAL COMPLIANCE AND ENFORCEMENT NEWS

NEW Resources Posted

NERC has posted the streaming webinar and slide presentation for the 2019 ERO CMEP Implementation Plan webinar.

Quick Links

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

OTHER NEWS

NEW Resources Posted

NERC has posted the streaming webinar and slide presentation for the November 13, 2018 Primary Frequency Response – Steam Generation webinar and the streaming webinar and slide presentation for the November 13, 2018 Natural Gas Combined Cycle/Simple Cycle webinar.

Nomination Period Open for New RISC Members

As the terms expire for a number of Reliability Issues Steering Committee (RISC) members on January 31, 2019, volunteers are being sought from the Member Representatives Committee (MRC) and industry to serve on the RISC for two-year terms ending January 31, 2021.

The RISC is an advisory committee that reports directly to the NERC Board of Trustees (Board) and triages and provides front-end, high-level leadership and accountability for issues of strategic importance to bulk power system (BPS) reliability and security. The RISC assists the Board, NERC standing committees, NERC staff, regulators, Regional Entities, and industry stakeholders in establishing a common understanding of the scope, priority, and goals for the development of solutions to these issues. In doing so, the RISC provides a framework for developing recommendations to help NERC and the industry effectively focus their resources on the critical issues needed to improve the reliability and security of the BPS. The 2017 ERO Reliability Risk Priorities Report was approved by the Board and is posted on the RISC web page. The RISC will develop a 2019 ERO Reliability Risk Priorities report to be presented to the Board for approval.

As described in the RISC charter, nominees for RISC should meet the following general qualifications:

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

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

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

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

If you are interested in nominating either yourself or another person, please complete the nomination form and send it to Tina Buzzard. **Nominations are due on or before December 19, 2018.**

STANDARDS SUBJECT TO FUTURE ENFORCEMENT

Please refer to the U.S. Effective Dates page for more detail on the standards listed below.

U.S. Effective Dates for Reliability Standards	
U.S. Effective Date	**Standard(s)**
January 1, 2019	BAL-005-1 – Balancing Authority Control
	FAC-001-3 – Facility Interconnection Requirements
	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirement 5, 5.1– 5.2)
	VAR-001-5 – Voltage and Reactive Control
April 1, 2019	BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event
	EOP-004-4 – Event Reporting EOP-005-3 – System Restoration from Blackstart Resources EOP-006-3 – System Restoration Coordination EOP-008-2 – Loss of Control Center Functionality
January 1, 2020	CIP-003-7 – Cyber Security — Security Management Controls
	PRC-026-1 – Relay Performance During Stable Power Swings (Requirements 2–4)
July 1, 2020	CIP-005-6 – Cyber Security – Electronic Security Perimeter(s) CIP-010-3 – Cyber Security — Configuration Change Management and Vulnerability Assessments CIP-013-1 – Cyber Security — Supply Chain Risk Management

	PRC-002-2 – Disturbance Monitoring and Reporting Requirements (50% compliance for Requirements 2–4, 6–11)
October 1, 2020	PER-006-1 – Specific Training for Personnel
	PRC-027-1 – Coordination of Protection Systems for Performance During Faults
January 1, 2021	PRC-012-2 – Remedial Action Schemes
	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements 6, 6.1–6.4)
January 1, 2022	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements 3,4,7)
July 1, 2022	PRC-002-2 – Disturbance Monitoring and Reporting Requirements (100% compliance for Requirements 2–4, 6–11)

BOARD OF TRUSTEES AND FERC ACTION

NEW NERC Filings

On November 29, 2018, NERC submitted to FERC an informational filing regarding the 2018 Frequency Response Annual Analysis report.

NERC's 2018 filings to FERC are available here.

UPCOMING EVENTS

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

Workshops and Conferences

- Eighth Annual Human Performance Conference – March 26–28, 2019, Atlanta | **SAVE THE DATE**

Webinars

- NEW Project 2017-01 – Modifications to BAL-003-1.1 Webinar – 11:00 a.m.–3:00 p.m. Eastern, January 25, 2019 | Register
- Methods for Establishing IROLs Task Force (MEITF) Informational Webinar – 1:00–12:30 p.m. Eastern, December 18, 2019 | Register

Standing Committee Meetings and Conference Calls

- Operating Committee, Planning Committee, and Critical Infrastructure Protection Committee Meetings – December 11–12, 2018, Atlanta | Register for OC | Register for PC | Register for CIPC | Register for Hotel | NEW CIPC Agenda
- Standards Committee Meeting – 10:00 a.m.–3:00 p.m. Eastern, December 12, 2018, Atlanta | Register
- NEW Board of Trustees Conference Call – 2:00–3:00 p.m. Eastern, December 13, 2018 | Agenda Package
- NEW Board of Trustees Committees, Member Representatives Committee, and Board of Trustees Committee Meetings – February 6–7, 2019, Manhattan Beach, CA | Register

Standard Drafting Team Meetings and Conference Calls

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

- Standards Efficiency Review – Phase 2 Meeting – 8:00 a.m.–5:00 p.m. Eastern, December 4, 2018, Atlanta | Register
- NEW Project 2016-02 Modifications to CIP Standards Conference Call – 11:00 a.m.–2:00 p.m. Eastern, December 4, 2018 | Register
- NEW Project 2018-02 – Modifications to CIP-008 Cyber Security Incident Reporting Conference Call – 2:00–4:00 p.m. Eastern, December 4, 2018 | Register
- Project 2017-01 – Modifications to BAL-003-1.1 Drafting Team Meeting – December 4–5, 2018, Charlotte, NC | Register
- Project 2018-02 – Modifications to CIP-008 Cyber Security Incident Reporting – December 11–13, 2018, Atlanta | Register
- NEW Project 2015-09 Establish and Communicate System Operating Limits Conference Call – 10:00 a.m.–Noon Eastern, December 19, 2018 | Register

ABOUT THE STANDARDS, COMPLIANCE, AND ENFORCEMENT BULLETIN

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

If you would like to receive this bulletin or be added to the distribution list for a particular project, please submit a ticket through the Help Desk. Select the "NERC Email Distribution List" option under the "Applications" menu. In the Description Box, please specify which lists you

would like your email address to be added to or note which announcements you would like to receive. This bulletin is distributed to several lists, including the Standards distro list (Standards-specific announcements) and the NERC-info distro list (most NERC announcements).

NPCC, Inc.

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. Directory Development and Revision Manual

&

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

Revised XX, XX, 2018
Cost Effectiveness Assessment



August 23, 2018

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	10/26/2011	Effective Date	New
1	12/5/2013	Revised	Revised Interpretation Approval Process
2	10/03/2014	Revised	Added NPCC CEAP Considerations
3	8/23/2018	Revised	Added Process for Review and Approval of Criteria, Guides, and procedures from Document A-01 to permit retirement of A-01
4		Revised	Update the Cost Effectiveness Assessment Expectations

I. CONTENTS

II. EXECUTIVE SUMMARY 4

III. BACKGROUND 4

III. APPLICABILITY OF NPCC CRITERIA 6

IV. TASK FORCE ROLES AND RESPONSIBILITIES 6

V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE 7

1. NEW DIRECTORY 7

2. DIRECTORY REVISIONS 10

a. Revisions to the Criteria Section of a Directory 10

b. Revisions to the Appendix Section of a Directory 13

c. Revisions To The NPCC Glossary Of Terms 15

d. Withdrawal Of Revision Requests 18

3. DIRECTORY RETIREMENT 18

4. MAINTENANCE OF LINKS AND ERRATA 18

VI. DIRECTORY CLARIFICATION PROCESS 19

a. Request for Criteria Clarification 19

B. APPEALS 22

VII. DIRECTORY FORMAT AND VERSION CONTROL 22

VIII. NPCC PROCEDURE FOR COST EFFECTIVE ANALYSIS OF PROPOSED AND REVISED CRITERIA IN DIRECTORIES 22

IX. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES 23

X. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL & PROCESS FOR THE REVIEW AND APPROVAL OF CRITERIA, GUIDELINES, AND PROCEDURES 29

APPENDIX A - DIRECTORY FORMAT TEMPLATE 30

APPENDIX B – NPCC REQUEST FOR CLARIFICATION 34

~~II. EXECUTIVE SUMMARY ..... 3~~

~~III. BACKGROUND ..... 3~~

~~III. APPLICABILITY OF NPCC CRITERIA ..... 5~~

~~IV. TASK FORCE ROLES AND RESPONSIBILITIES ..... 5~~

~~V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE ..... 6~~

~~1. NEW DIRECTORY ..... 6~~

~~2. DIRECTORY REVISIONS ..... 9~~

~~*a. Revisions to the Criteria Section of a Directory ..... 9*~~

~~*b. Revisions to the Appendix Section of a Directory ..... 12*~~

~~*c. Revisions To The NPCC Glossary Of Terms ..... 14*~~

~~*d. Withdrawal Of Revision Requests ..... 17*~~

3. DIRECTORY RETIREMENT 17
4. MAINTENANCE OF LINKS AND ERRATA 17
VI. DIRECTORY CLARIFICATION PROCESS 18
a. *Request for Criteria Clarification* *18*
b. APPEALS 21
VII. DIRECTORY FORMAT AND VERSION CONTROL 21
VIII. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES 21
IX. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL & PROCESS FOR THE REVIEW AND APPROVAL OF CRITERIA, GUIDELINES, AND PROCEDURES 26
APPENDIX A - DIRECTORY FORMAT TEMPLATE 27
APPENDIX B – NPCC REQUEST FOR CLARIFICATION 31

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II. EXECUTIVE SUMMARY

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

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

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

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

Accordingly, some aspects of the ~~the fundamental review methodology of the~~ NPCC Cost Effectiveness Analysis Procedure (CEAP) for the development of Regional Standards ~~has~~ have been incorporated into the~~e~~is Directory Development and Revision Manual and appear in Section VIII.

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

III. BACKGROUND

NPCC Directories have been developed consistent with the NPCC Bylaws which provide for the establishment of regionally specific reliability criteria, guidelines and

procedures; within each Directory NPCC's reliability criteria has been reviewed and translated to ensure that the criteria is not inconsistent with the ERO standards as required by the NERC Rules of Procedure.

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

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

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

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

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

Most of NPCC's "B" Guideline and "C" Procedure documents were transferred to Directories as Appendices in support of the relevant criteria. Those B and C documents that were not incorporated into a Directory remain as standalone documents. Phase 2 work has been completed.

III. APPLICABILITY OF NPCC CRITERIA

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

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

IV. TASK FORCE ROLES AND RESPONSIBILITIES

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

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

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

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

The Lead Task Force will also consider the cost effectiveness of the criteria within the Directory during each periodic review of the document or for any proposed revisions to the criteria. Cost effectiveness activities will be conducted as outlined in Section VIII and

~~The Cost Effectiveness Analysis (CEA) of the criteria will consist of~~ utilize survey questions developed by the Task Force to accompany ~~an initial~~ comment period(s) and which are designed to solicit Member comment on whether the ~~c~~Criteria represents an incremental benefit to reliability and whether there are any cost effective alternatives to achieving a similar or greater level of reliability. As noted in Section VIII, the Lead Task Force may waive the cost effectiveness or conduct it any time during the process. In all cases, the Lead Task Force will document its cost effectiveness decisions and activities.

V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE

1. NEW DIRECTORY

Any NPCC Full Member may request the development of a new Directory. The request shall be made to the NPCC Manager of Reliability Criteria via email and shall contain the background and justification for the development of the new Directory as well as any cost of implementation information that may be available.

The NPCC Manager of Reliability Criteria shall forward the request for the development of a new Directory, ~~along with a request for the RSC to authorize a Cost Effectiveness Analysis utilizing the NPCC CEAP procedure to the Regional Standards Committee (RSC). The RSC will review the request and assign the request to develop a new Directory~~ to the appropriate Task Force (TF) and copy the Regional Standards Committee (RSC). The Lead Task Force responsible for developing the new Directory shall review the request and all information submitted and determine if the development activity is warranted. If the TF accepts the request, it will draft an initial version of the document consistent with the Directory template in Attachment A.

The ~~RSC~~TF, working with NPCC Staff, shall ~~utilize the NPCC CEAP to~~ perform an initial analysis of the cost of implementation and effectiveness ~~benefit~~ of the proposed Directory as noted in Section VIII~~via the Cost Benefit Analysis (CBA) section of the CEAP~~. Results of the cost effectiveness activities will be reviewed by the TF and a recommendation made to the RSC. The RSC will review the TF recommendation and conclude whether the new Directory should move forward based on its reliability benefit and cost of implementation. If

~~In accordance with the CBA section of the CEAP if~~ the RSC concludes that the development of a new Directory is not cost effective the RSC will forward the results of the CBA to the Manager of Reliability Criteria for notification to the Lead Task Force and NPCC Full Member.

After the RSC reviews and approves the development of the new Directory~~CBA~~ the Lead Task Force shall post the draft Directory to the NPCC Open Process for 45 days.

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

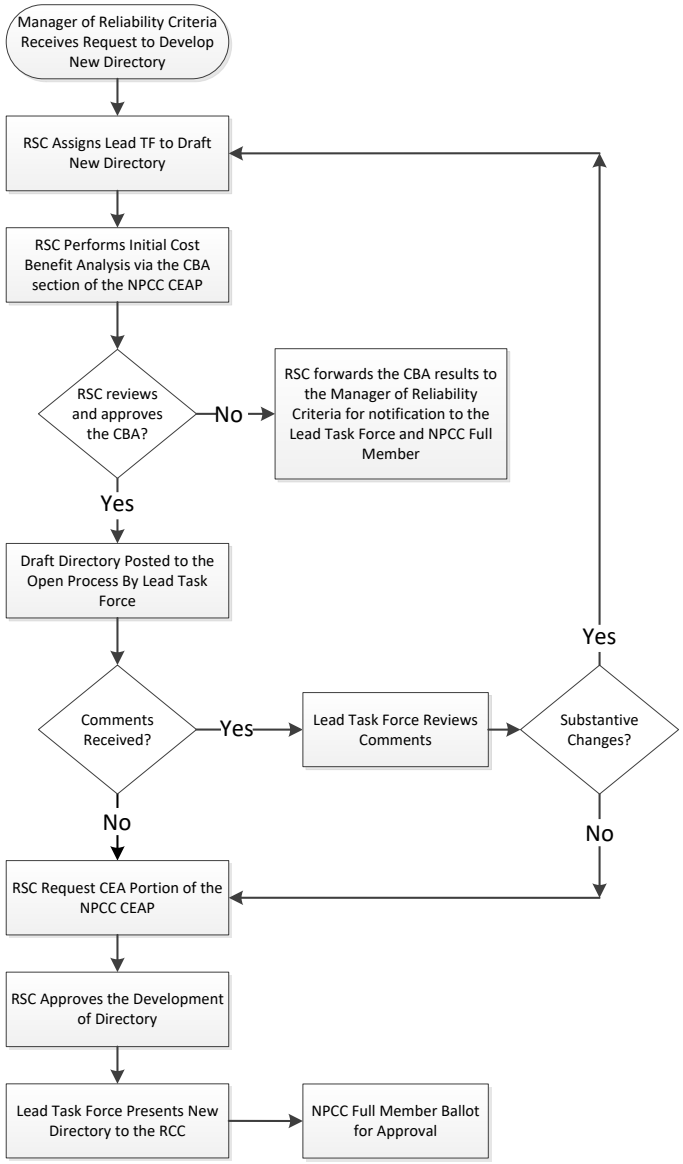
If the responses to comments received on the draft result in substantive changes to the document, the revised draft shall be reposted to the Open Process for a successive 45 day posting period. The process of comment review, revision and re-posting for comment continues until no substantive modifications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

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

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

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

Figure 1: New Directory



2. DIRECTORY REVISIONS

a. REVISIONS TO THE CRITERIA SECTION OF A DIRECTORY

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

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

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

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

~~In accordance with the CBA section of the CEAP if the RSC concludes that the revision to an existing Directory is not cost effective the RSC will forward the results of the CBA to the Manager of Reliability Criteria for notification to the Lead Task Force and NPCC Full Member.~~

The Lead Task Force shall review the request to revise the criteria and shall also consider conforming changes to appendices as a result of the criteria revision if necessary.

The Lead Task Force will also consider the cost effectiveness of the criteria within the Directory during each periodic review of the document or for any proposed revisions to the criteria.

The cost effectiveness of the criteria will consist of survey questions developed by the Task Force and which are designed to solicit Member comment on the relative cost of different approaches to achieving the level of reliability provided by the criteria.

These survey questions will accompany the posting of the Directory in order to promote transparency.

~~The Cost Benefit Analysis section of the NPCC Cost Effectiveness Analysis Procedure (CEAP)~~Section VIII provides guidance for this analysis.

The NPCC Manager of Reliability Criteria shall post the Directory containing the revised criteria to the NPCC Open Process review for 45 days along with the survey questions developed to assess the cost effectiveness of the criteria.~~,~~ The survey responses will be documented and archived as part of the record of the Task Force review.

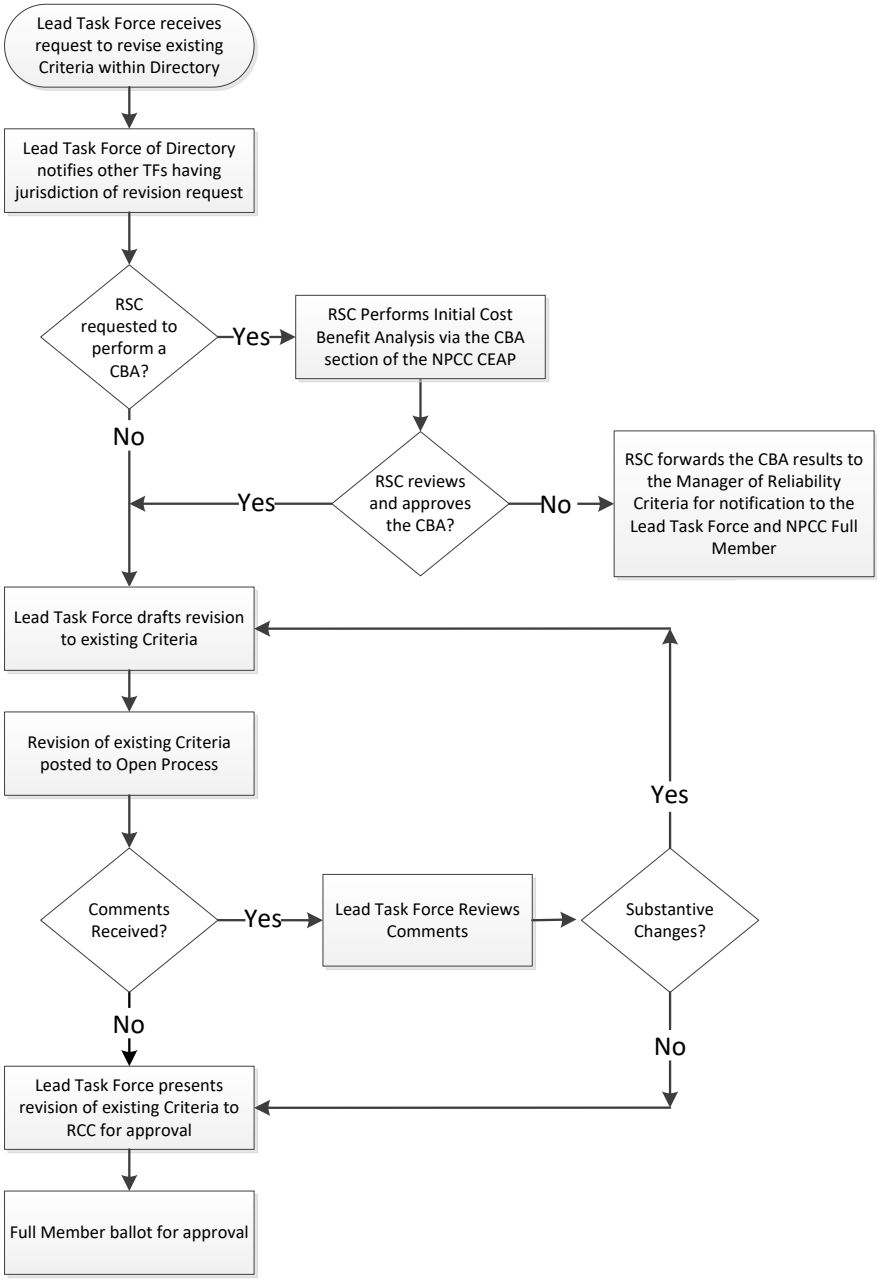
At the conclusion of the 45-day Open Process, the Lead Task Force will discuss the comments submitted and post responses to comments on the NPCC Open Process portal. If the responses to the comments received on the criteria revision result in substantive changes to the document, then the revised Directory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

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

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

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

Figure 2: Revisions to Criteria



b. REVISIONS TO THE APPENDIX SECTION OF A DIRECTORY

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

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

The Lead Task Force of the Directory shall be responsible for notifying all Task Forces which have jurisdiction over either the criteria or one or more of the other Appendices within the Directory that a request to revise, add or retire an appendix has been received. The Lead Task Force at this time will also determine whether to waive or conduct cost effective activities.

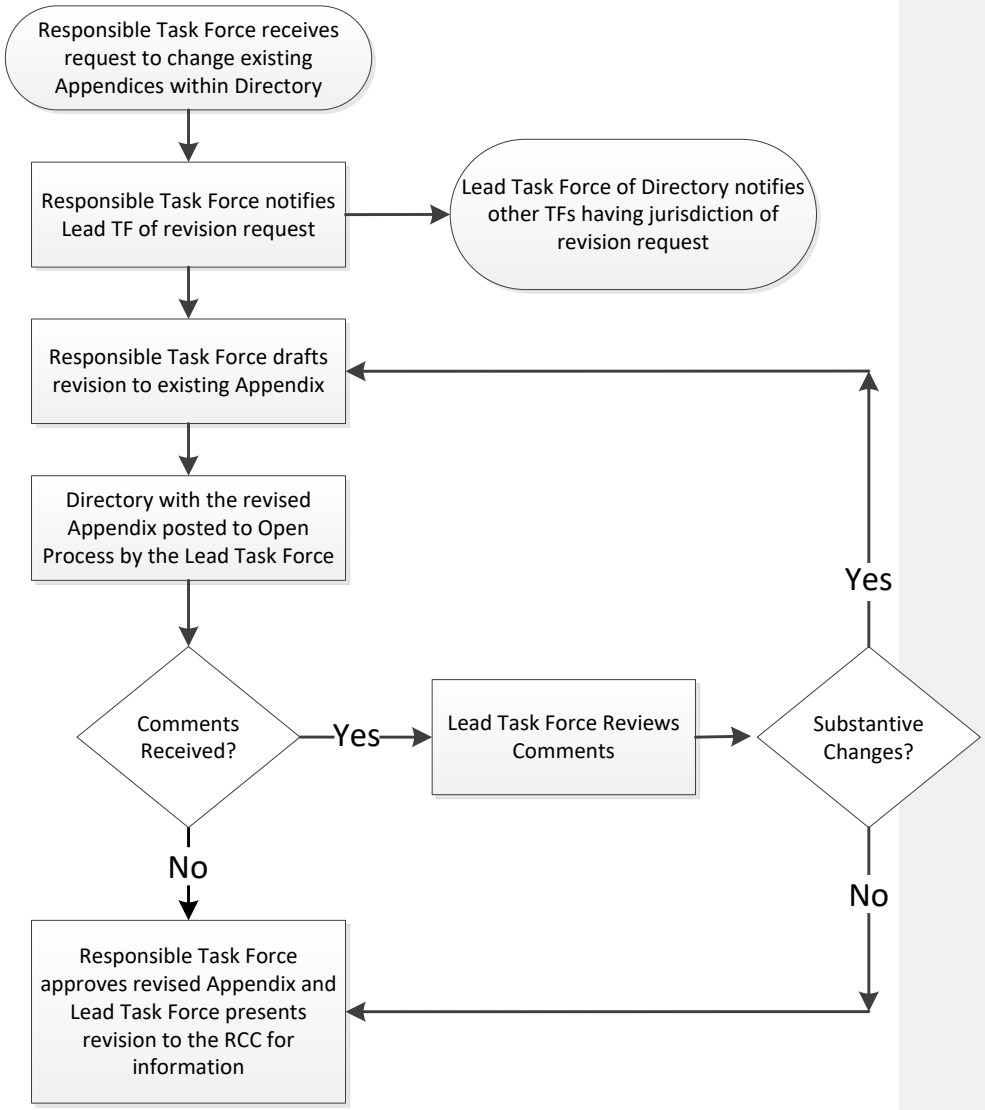
After the Task Force responsible for the revised Appendix request reviews the subject Appendix they will forward the Directory containing the draft revised Appendix to the Lead Task Force of the Directory. The Lead Task Force shall be responsible for posting the Directory (in its entirety) which contains the new, revised or retired Appendix to the NPCC Open Process review for 45 days and will also conduct the cost effectiveness activities as noted in Section VIII as may be necessary. The Lead Task Force will limit the comments solicited to only the subject Appendix.

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

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

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

Figure 3: Revisions to Appendices



c. REVISIONS TO THE NPCC GLOSSARY OF TERMS

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

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

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

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

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

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

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

In accordance with the CBA section of the CEAP if the RSC concludes that the development of a new or revised Glossary term is not cost effective the RSC will forward the results of the CBA to the Manager of Reliability Criteria for notification to the Lead Task Force and NPCC Full Member.

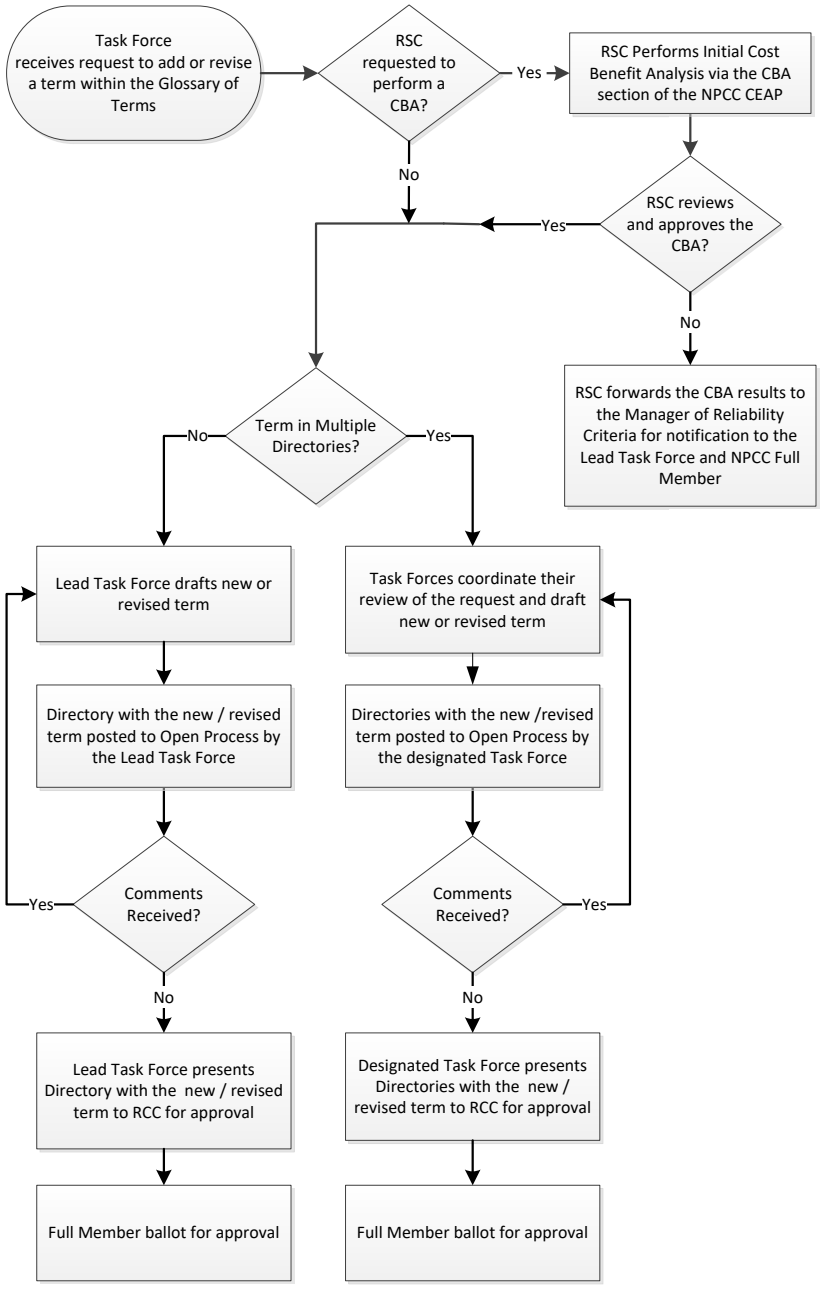
After the Lead Task Force in which the defined term resides has completed its review they will post the subject Directory containing the new or revised term to the NPCC Open Process for 45 days. When the new or revised term appears in multiple Directories, the designated Lead Task Force for the review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

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

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

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

Figure 4: Revisions to the NPCC Glossary of Terms



d. Withdrawal Of Revision Requests

Any NPCC Full Member which has initiated a request to develop a new Directory, revise an existing Directory or revise an NPCC Glossary Term may withdraw the request at any time prior to Full Member approval of the revised Directory or NPCC Glossary Term by notifying the NPCC Manager of Reliability Criteria. The NPCC Manager of Reliability Criteria will then notify the Lead Task Force, RSC and RCC.

3. Directory Retirement

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

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

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

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

4. Maintenance of Links and Errata

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

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

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

VI. DIRECTORY CLARIFICATION PROCESS

a. REQUEST FOR CRITERIA CLARIFICATION

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

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

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

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

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

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

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

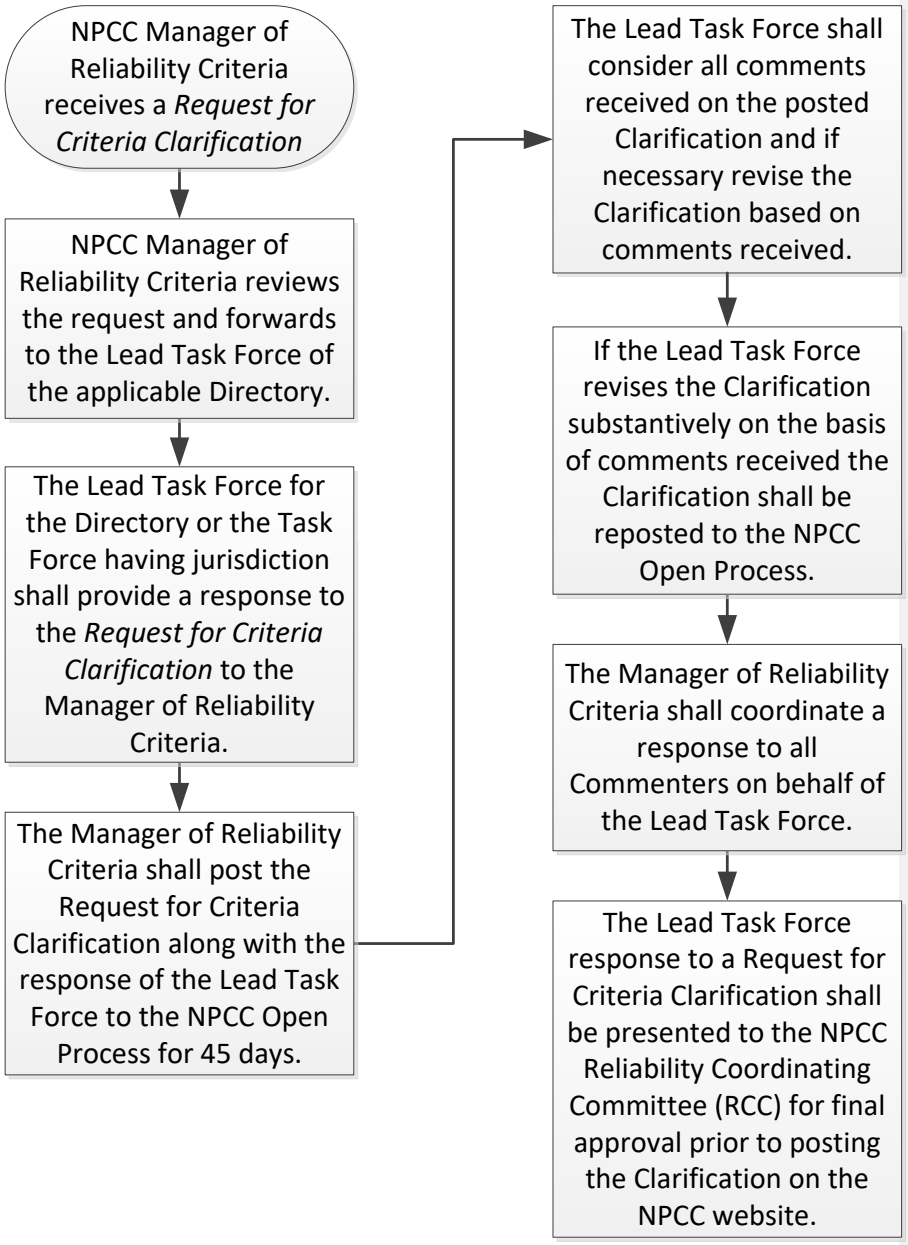
The NPCC Manager of Reliability Criteria shall review the clarification provided by the Lead Task Force or the Task Force having jurisdiction to ensure that it is clear and provides the requested explanation without expanding on the criteria.

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

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

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

Figure 5: Request for Criteria Clarification



b. APPEALS

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

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

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

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

VII. DIRECTORY FORMAT AND VERSION CONTROL

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

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

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

VIII. NPCC PROCEDURE FOR COST EFFECTIVE ANALYSIS OF PROPOSED AND REVISED CRITERIA IN DIRECTORIES

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1. Upon receipt of a request to review or revise the criteria in an existing Directory, by an NPCC Full Member, or a request to develop a new Directory, the Task Force having jurisdiction (Lead Task Force) will determine if the activity warrants conducting cost effectiveness activities.

2. The Lead Task Force will document this initial determination as part of the record of development and notify the RCC and RSC of intent to conduct cost effectiveness activities or exercise a waiver.

3. If the Task Force later determines that conducting cost effectiveness activities is warranted at any time during the development process of the new or revised Directory, the Task Force will notify the NPCC Manager of Reliability Criteria.

4. NPCC will coordinate the necessary cost effective activities as directed by the Task Force. These activities will focus on identification of the incremental reliability benefit of the Criteria and the implementation cost and cost effectiveness associated with that benefit. The Lead Task Force shall use the subject matter expertise of its members as well as other TFs as may be applicable along with the open process posting(s) for comment to gather this information (See below for sample questions).

- Does the proposed Criteria address an increased level or benefit of reliability which is necessary to protect NPCC's reliability? If not, why not (probabilistic data may be used to make a determination)?
- What approximate implementation and ongoing estimated potential costs would be associated with compliance with the proposed Criteria?
- Is there a more cost effective solution to achieving the same or greater level reliability if a different approach was taken? If so what is that solution?
- How long would it take your organization to implement full compliance to the Criteria as written? What would affect the implementation (i.e. outage scheduling, availability of materials, human resources, etc.)?

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5. The Task Force shall use the information obtained, to make a determination if the cost to implement the revised or new Criteria is of sufficient reliability benefit to pursue further development activities by NPCC or if other approaches to achieve the reliability objective of the Criteria should be pursued. (e.g. development of a whitepaper, guideline document, etc.)

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

Introduction

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

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

Document, Criteria - Type "A"

General Description

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

Review and Approval

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

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

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

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

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

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

The approved and adopted Type "A" document will then be posted, along with necessary additional documentation, if needed, such as an implementation plan or

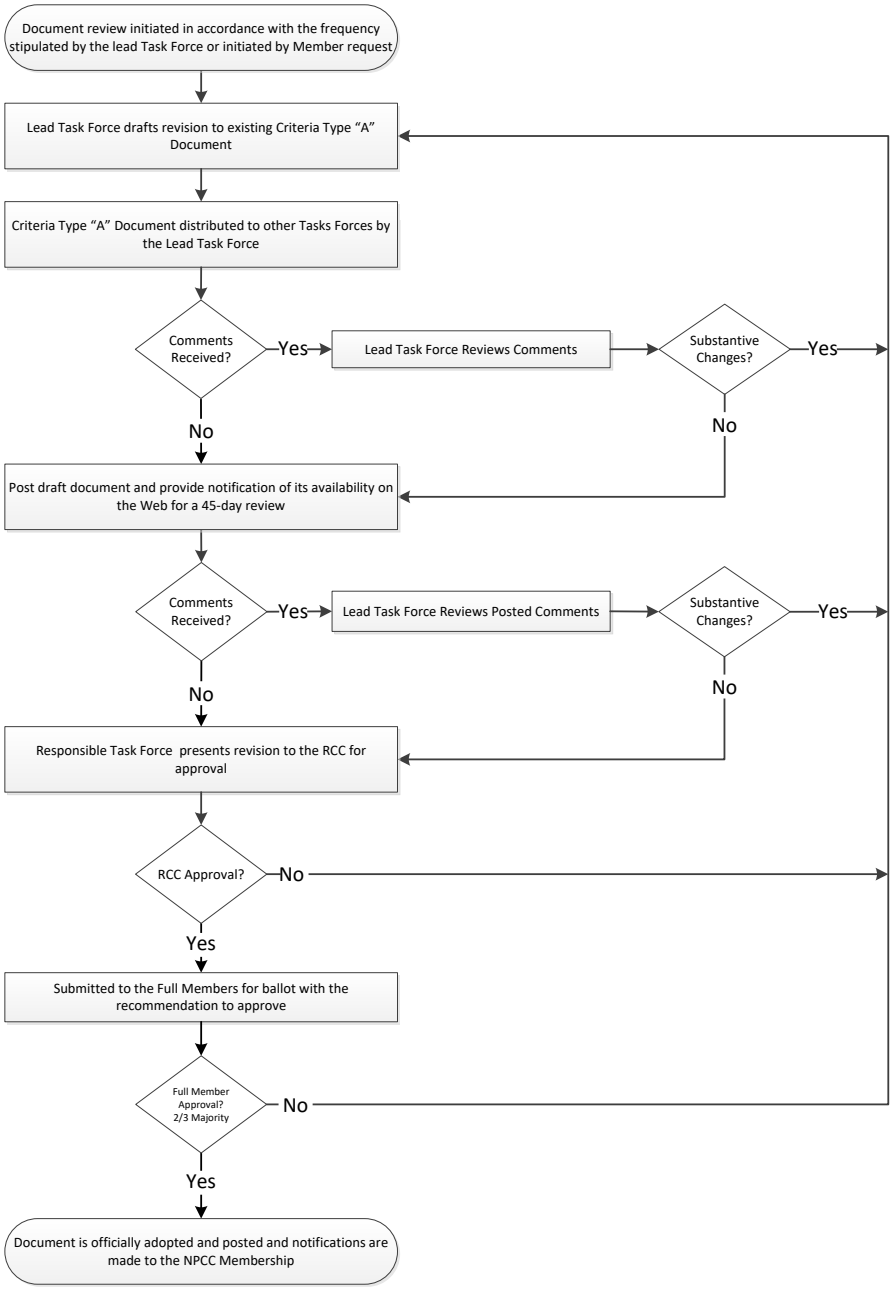
schedule for achieving full compliance with the requirements outlined in the document. This will be posted on the NPCC web site and distributed to the membership via a documented and maintained distribution list.

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

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

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

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



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

General Description

Type "B" documents are guideline documents.

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

Review and Approval

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

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

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

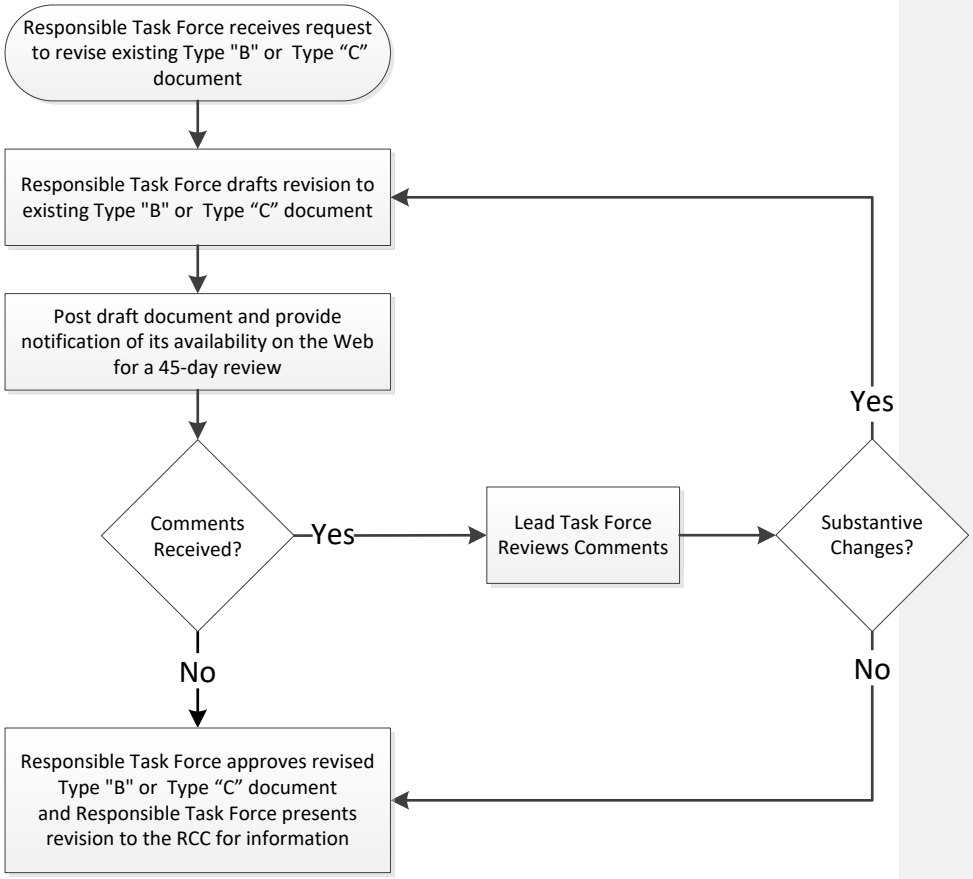
The revised B or C document (or the proposal to retire a B or C document) shall be posted to the NPCC Open Process for a 45-day posting.

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

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

The process for revisions to an existing Type "B" and "C"document is represented below in Figure 7:

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



~~IX.~~ X. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL & PROCESS FOR THE REVIEW AND APPROVAL OF CRITERIA, GUIDELINES, AND PROCEDURES

The NPCC Directory Development and Revision Manual & Process for the Review and Approval of Criteria, Guidelines, and Procedures will be reviewed at least once every five (5) years or more frequently if required.

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

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

APPENDIX A - DIRECTORY FORMAT TEMPLATE



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

NPCC
Regional Reliability Reference Directory # XX

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

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

Revision History

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

Format for NPCC Directories (Phase 2)

Effective Dates (Denotes date of adoption by the Membership)

Revision History (Depicts revision history and tracks key changes)

Table of Content (Self-explanatory)

A. Introduction

Title: Self-explanatory

Directory #: Self-explanatory

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

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

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

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

B. NERC ERO Reliability Standard Requirements

A list of the NERC standards associated with this Directory.

C. NPCC Regional Reliability Standard Requirements

A list of NPCC Regional Standards associated with this Directory.

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

Requirements

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

E. Compliance

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

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

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

APPENDIX B – NPCC REQUEST FOR CLARIFICATION



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

NPCC Request for Criteria Clarification

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

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

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

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

201~~9~~8 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 ~~each~~ any new and revised NERC Reliability Standard Audit Worksheet (RSAW), as may be requested by the NPCC Compliance Committee, and submit~~ting~~ 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 ~~such as~~ 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, ~~and~~ maintain, and further develop the process as necessary.
(~~i~~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 ~~c~~Co-~~v~~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 ~~m~~Members (the two elected RSC ~~m~~Members will be comprised of a Canadian representative and a U.S. representative). Additionally, the two RSC ~~m~~Members elected to the RSC Executive Committee by the RSC membership will serve ~~for~~ a two-year term.

Members of the RSC will be nominated by their respective companies. NPCC RSC leadership (RSC Chairperson and Co-Vice Chairpersons) will review and consider the approval of ~~the~~all nominations to the RSC. The nominations ~~which~~ will include contact information and qualifications to serve on the committee. ~~Appointments to the RSC will be approved by the RSC Executive Committee.~~ Each of the NPCC Sectors as defined in the NPCC Amended and Restated Bylaws will be open to represent~~ed~~ation on the RSC by qualified candidates 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 ~~power system~~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 ~~ensuring~~ the quality of all Standards-related materials.

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

B. NPCC Directory and Criteria Process Responsibilities

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

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~~98~~-2020~~19~~

The following Regional Standards Committee (RSC) Work Plan activities for the calendar years of 2019~~98~~ - 2020~~19~~ will be consistent with the NPCC 2019~~98~~ and 2020~~19~~ 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, ~~and~~ standards efficiency review, and metric activities. Also, the Work Plan is responsive to the NERC Reliability Standards Development Process, ~~and~~ the ERO Enterprise Long-Term Strategy, and the ERO Enterprise Operating plan~~strategic goals~~.

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 ~~s~~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 ~~r~~Regional participation in the Periodic Review Standing Review Team.
3. Review and support the ERO standards efficiency initiative (Phase 1 and Phase 2) 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 ~~provide~~coordinate Regional input ~~for consideration of~~for cost effectiveness activities ~~in~~conducted during NERC's Standards Development program.
5. Oversee, and participate in the ~~r~~Regional ~~s~~Standards ~~d~~Development ~~p~~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's ~~Orders~~ and any Provincial ~~regulatory~~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.
~~12.~~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.
~~13.~~14. Develop ballot recommendations or provide a list of " reliability or compliance issues ~~statements"~~ ~~for~~to RSC members and NERC Registered Ballot Pool entities within NPCC for all NERC Standards under development.
~~14.~~15. Review and develop ballot recommendations for all NERC formal interpretations to Standards.
~~15.~~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.
~~16.~~17. Respond to FERC and Provincial filings and interrogatories on issues related to ~~r~~Regional and NERC Standards as requested.
~~17.~~18. Serve as a liaison for the Northeast Region to the NERC Reliability Issues Steering Committee for all new and emerging reliability risks ~~to the BES~~.
~~18.~~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 Functional Model Advisory Group (FMAG)~~
    ~~e.~~d. NERC SAR and Standards Drafting Teams (SDTs)
    ~~f.~~e. NERC Reliability Issues Steering Committee (RISC)
    f. NERC Standards Efficiency Review (SER) Teams
    g. NERC Standards Drafting Teams
~~19.~~ 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.
20. ~~Promote the NPCC Criteria as augmenting and providing specificity to NERC standards requirements or addressing reliability risk issues not addressed in existing NERC standards. Coordinate efforts with the NPCC Compliance Committee to facilitate further development of the NPCC Criteria Compliance Enforcement Program (CCEP) via Phase 2 of the Directory Project which was initiated to reformat the criteria section of each Directory into measurable NERC-style requirements.~~
21. Develop proposed standards and standard clarifications utilizing regional technical committees as assigned by the NPCC Reliability Coordinating Committee, RSC or as identified through the NPCC Regional Feedback Mechanism.
22. Work with the NPCC CC to develop the necessary compliance elements of the 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~~,~~. ~~and p~~Promote and participate in the NERC cost effectiveness analysis ~~approach~~activities conducted during formal industry comment periods ~~to~~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

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~~28.~~ Participate in the revision and redrafting of the NERC Rules and Procedures and other documents related to standards development ~~such as, but not limited to:~~

~~a.~~28. ~~The NERC Functional Model Working Group (FMWG)~~

~~b. The NERC Standards Committee (SC)~~

~~c. The NERC Standards Committee Process Subcommittee (SCPS)~~

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."

~~29.~~32. Coordinate and work with State and Provincial Governmental Authorities to address reliability related issues associated between DERs and the ERO or Regional Standards.

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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 ~~a~~Authorities.
2. Identify the need for new or modified NPCC Directories and the Criteria, Guidelines and Procedures ~~within~~ pursuant to Section 313 of the NERC ROP responsibilities
3. Oversee a broad review for the development, modification, or retirement of Directories in accordance with the NPCC Directory Development and Revision Manual

~~3.~~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.

~~4.~~5. Coordinate Directory Criteria requirements with Regional and NERC Standards requirements to ensure no inconsistencies exist and identify potential areas for improvements.

~~5.~~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~~Regional criteria for New York State.

~~6.~~7. Develop filings of Directories as required with the Provincial Governmental ~~a~~Authorities as per the various Memorandums of Understanding.

~~7.~~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 R~~r~~egionally-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.

NORTHEAST POWER COORDINATING COUNCIL, INC.
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Northeast Power Coordinating Council, Inc.

Regional Standard Processes Manual (RSPM)



Approved by FERC: December 23, 2014

Approved by NERC Board of Trustees: August 14, 2014

Approved by NPCC Board of Directors: March 11, 2014

Revision History

Version	NPCC Board of Directors Approval	NERC Board of Trustees Approval	FERC Approval
0	9/19/07	10/23/07	3/21/08
1	3/11/14	8/14/14	12/23/14
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NPCC REGIONAL RELIABILITY STANDARDS PROCESS MANUAL

TABLE OF CONTENTS

I. EXECUTIVE SUMMARY 3
II. INTRODUCTION 4
PURPOSE 4
BACKGROUND 4
III. REGIONAL STANDARD CHARACTERISTICS AND ELEMENTS 5
1. CHARACTERISTIC ATTRIBUTES 5
2. ELEMENTS OF A REGIONAL STANDARD 6
TYPES OF RELIABILITY REQUIREMENTS 6
ELEMENTS OF A REGIONAL STANDARD 7
IV. REGIONAL STANDARDS DEVELOPMENT PROCESS 9
1. ROLES IN THE NPCC REGIONAL STANDARD PROCESS 9
NOMINATION, REVISION, CLARIFICATION, OR RETIREMENT OF A STANDARD: 9
PROCESS ROLES AND RESPONSIBILITIES 9
2. STANDARD DEVELOPMENT PROCESS STEPS 11
STEP 2.1: REGIONAL STANDARDS AUTHORIZATION REQUEST TO DEVELOP, MODIFY OR RETIRE 11
STEP 2.2: FORMATION OF DRAFTING TEAM FOR NEW OR MODIFIED STANDARD 12
STEP 2.3: DEVELOPMENT OF A REGIONAL STANDARD AND ASSOCIATED DOCUMENTS 13
STEP 2.4: POSTING FOR COMMENT PERIOD AND RESOLUTION OF COMMENTS 14
STEP 2.5: POSTING FOR BALLOT PERIOD IN THE OPEN PROCESS 16
STEP 2.6: NPCC BOARD OF DIRECTORS APPROVAL 17
STEP 2.7: NERC BOARD OF TRUSTEES SUBMITTAL 18
STEP 2.8: IMPLEMENTATION OF A NPCC REGIONAL STANDARD 18
3. STANDARD CLARIFICATION PROCESS STEPS 19
STEP 3.1: REGIONAL STANDARDS CLARIFICATION REQUEST (CR) 19
STEP 3.2: REVIEW AND VALIDATION OF CLARIFICATION REQUEST (CR) 19
STEP 3.3: NPCC REGIONAL STANDARDS COMMITTEE (RSC) ACTIONS 20
STEP 3.4: FORMATION OF DRAFTING TEAM FOR RESPONSE TO CR 20
STEP 3.5: DEVELOPMENT OF RESPONSE TO CR 20
STEP 3.6: POSTING CR FOR COMMENT PERIOD AND RESOLUTION OF COMMENTS 21
STEP 3.7: REGIONAL STANDARDS COMMITTEE APPROVAL OF CR 21
STEP 3.8: NPCC BOARD OF DIRECTORS APPROVAL OF CR 21
4. DISCONTINUANCE OF REGIONAL STANDARD DEVELOPMENT 22
5. WITHDRAWAL OF A REGIONAL STANDARD PENDING APPROVAL 23
6. RETIREMENT OF AN APPROVED NPCC REGIONAL STANDARD 23
7. APPROVAL OF PROCESS WAIVER 23
8. PROCESS FOR CORRECTING ERRATA 24
9. APPEALS 24
LEVEL 1 APPEAL 25
LEVEL 2 APPEAL 25
APPENDIX A: RSAR COMPLETION GUIDELINES A1
APPENDIX B: SELECTION OF DRAFTING TEAM MEMBERS B1
APPENDIX C: MAINTENANCE OF REGIONAL STANDARDS AND PROCESS ... C1
MAINTENANCE OF REGIONAL STANDARDS C1
MAINTENANCE OF THE REGIONAL STANDARDS PROCESS C1
APPENDIX D: NPCC CLARIFICATION REQUEST D1

I. EXECUTIVE SUMMARY

The NPCC Bylaws state "NPCC shall develop a Regional Reliability Standards Development Procedure that provides the design-basis approach to a consensus building process by which NPCC may develop Regional Reliability Standards and Regional Variances to be proposed to the ERO for adoption, under delegated authority by the FERC and the Canadian Provincial regulatory and/or governmental authorities."

The NPCC Regional Reliability Standards Development Procedure was originally adopted by the NPCC Board of Directors on September 19, 2007. The NPCC Reliability Standards Staff in concert with the NPCC Regional Standards Committee (RSC) has completed a revision to the NPCC Regional Reliability Standards Process Manual to incorporate process improvements, provide greater clarity and reflect the new NPCC Cost Effectiveness Analysis Procedure (CEAP).

Key changes addressed in this revision include:

- Replacing interpretation with clarification and expanding the Clarification Section narrative into process steps and including an associated flowchart
- Creating separate sections for: 1) Withdrawal of a Regional Standard Pending Approval; 2) Retirement of an Approved NPCC Regional Standard; and 3) Approval of Process Waiver; 4) Process for Correcting Errata
- Recognizing the new NPCC Cost Effectiveness Analysis Procedure (CEAP)
- Identifying the Reliability Standard Audit Worksheet (RSAW) as a companion document to a regional standard that needs to be collaboratively developed by the drafting team and NPCC Compliance Staff
- Creating three new appendices: 1) Appendix A: Regional Standard Authorization Request (RSAR) Completion Guidelines and Form; 2) Appendix B: Selection of drafting team Members and Nomination Form; and 3) Appendix C: Maintenance of Regional Standards and Process

In addressing areas for improvement in the NPCC Regional Reliability Standards Development Procedure, recent improvements made to the NERC Standards Process Manual (e.g., Standards Process Input Group (SPIG) recommendations) as well as the manuals of other Regional Entities were benchmarked to identify best practices for inclusion in this manual.

The process improvements and clarity captured in this revision to the NPCC Regional Reliability Standards Development Procedure, will result in a more timely and efficient manner to address the development of regional standards to ensure the reliability of the Bulk Electric System within the NPCC geographical area.

II. INTRODUCTION

PURPOSE

This manual defines the characteristics of a Northeast Power Coordinating Council, Inc. (NPCC) regional Reliability Standard (hereinafter referred to as "regional standard") and establishes the process by which NPCC regional standards are developed, approved, revised, clarified and retired. The NPCC regional standards process is a stakeholder process that is approved by the NPCC members to ensure a transparent standard development process that is "open, fair, and inclusive."

NPCC regional standards address the reliability of the international and interconnected Bulk Electric System in Northeast North America. NPCC regional standards shall enable or support one or more North American Electric Reliability Council/Electric Reliability Organization NERC/ERO reliability principles[1] and will, in all cases, not be inconsistent with or less stringent than any requirements of the ~~North American Electric Reliability Council/Electric Reliability Organization (~~NERC/ERO~~)~~ continent-wide Reliability Standards.

The development of NPCC regional standards is performed according to the following principles using the process contained in this manual:

- Developed in a fair and open process that provides an opportunity for all interested parties to participate;
- Does not have an adverse impact on commerce that is not necessary for reliability;
- Provides a level of Bulk Electric System reliability that is adequate to protect public health, safety, welfare, and national security and would not have a significant adverse impact on reliability; and
- Based on a justifiable difference between Regions or between sub-Regions within the Regional geographic area.

Following industry approval, NPCC regional standards process and NPCC regional standards require approval by the NPCC Board of Directors, NERC as the Electric Reliability Organization (ERO) and the applicable regulatory authorities in the United States (FERC) and Canada.

BACKGROUND

Northeast Power Coordinating Council, Inc. (NPCC) is responsible for promoting and improving the reliability of the international, interconnected Bulk Electric System in Northeastern North America. NPCC carries out its mission through (i) the development of regional standards and compliance assessment and enforcement of continent-wide and regional 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").

The Energy Policy Act (EPA) of 2005 (Section 1211) amended the Federal Power Act (FPA) by adding Section 215, Electric Reliability. Specifically regarding standards development and pursuant with Section 215(e)(4) of the FPA, NPCC as a Regional Entity with delegated authority from NERC may propose regional standards to NERC for eventual enforcement within the NPCC region.

[1] Reliability Principles are available on the NERC website as amended from time to time Link:

https://www.nerc.com/pa/Stand/Resources/Documents/Reliability_Principles.pdf#search=reliability%20Principles

As a condition of NPCC membership, NPCC General and Full Members[2] agree to adhere to NERC Reliability Standards. NERC Reliability Standards are comprised of both continent-wide and regional standards. The NPCC regional standards apply only to that part of the Eastern Interconnection within the NPCC geographical area.

III. REGIONAL STANDARD CHARACTERISTICS AND ELEMENTS

1. CHARACTERISTIC ATTRIBUTES

The NPCC regional standards development process has the following key characteristics:

- **Fair- due process** — The NPCC regional standards development process provides for reasonable notice and opportunity for public comment. At a minimum, the procedure shall include public notice of the intent to develop a standard, a public comment period on the proposed standard, due consideration of those public comments, and a ballot of interested stakeholders. Upon approval by the NPCC Members, the NPCC Board of Directors then votes to approve submittal of the regional standard to NERC for ERO approval, followed by submission to FERC and Canadian Authorities for their approvals.
- **Openness** — Participation in the NPCC regional standards development process is open to all persons and organizations that are directly and materially affected by the reliability of the NPCC's Bulk Electric System. There is no undue financial burden to participation. Participation shall not be conditioned upon membership in the ERO, NPCC or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.
- **Inclusive** — Any entity (person, organization, company, government agency, individual, etc.) with a direct and material interest in the reliability of NPCC's Bulk Electric System has the right to participate by: (a) expressing an opinion and its basis; (b) having their position considered, and (c) having the right to appeal a response through an established appeal process.
- **Balanced** — The NPCC regional standards development process strives to have an appropriate balance of interest and shall not be dominated by any two interest categories and no single interest category shall be able to defeat a matter. Pursuant with the NPCC By-Laws[3] there are seven (7) stakeholder voting sectors and the votes for each sector are weighted to achieve an appropriate balance.
- **Transparent** — All actions material to the development of NPCC regional standards are transparent and information regarding the progress of a standard's development action is made available to the public through postings on the NPCC website as well as through E-mail lists.
- **Without undue delay** — The NPCC regional standards development process shall be performed within a reasonable time.

In as much as NPCC is one of six Regional Entities within the Eastern Interconnection of North America, there will be no presumption of validity by the ERO for any NPCC regional standard.

Commented [RS1]: Quintin Lee suggest we combine "Openess" with "Transparency"

[2] As defined in the NPCC By-Laws – available on the NPCC website

[3] NPCC By-Laws are available at this link~~on the NPCC By-Laws~~

Commented [HS2]: Do we need both footnotes here? If we have them the links should be live links.

In order to receive the approval of the ERO, the NPCC regional standards development process must also achieve the following objectives:

- **No Adverse Impact on Reliability of the Interconnection** — A NPCC regional standard provides an Adequate Level of Reliability[4] as defined by NERC.
- **Justifiable Difference** — A NPCC regional standard addresses a justifiable difference within the NPCC geographical area that results from a physical difference[5] or operating difference in the Northeast's Bulk Electric System. Although a justifiable difference allows for a unique regional standard, a NPCC regional standard shall be no less stringent than a continent-wide standard covering the same reliability risks.
- **Uniformity** — To the extent possible, the NPCC regional standards provide~~s~~ uniformity with Reliability Standards across the interconnected Bulk Electric System of North America.
- **No Undue Adverse Impact on Commerce** — A NPCC regional standard will not cause any undue adverse impact on business activities that are not necessary for reliability of the power system in the Region and ~~its~~ neighboring Interconnections~~interconnected Regions~~. All regional standards shall be consistent with NERC's market principles[6].

Commented [RS3]: Quintin Lee suggest adding that new Standards are "coordinated with existing NERC Standards."

Commented [HS4]: A regional standard can not promote uniformity across the BES in North America. It creates a difference.

2. Elements of a Regional Standard

To ensure uniformity of regional standards and avoid inconsistency with NERC continent-wide standards, a NPCC regional standard shall be consistent with the elements identified in this section of the procedure. These elements are intended to apply a systematic discipline in the development and revision of regional standards. The application of a systematic discipline is necessary for implementing~~achieving~~ regional standards that are measurable, enforceable, and consistent as well as results oriented[7], i.e.:

- Performance-based,
- Risk-based, and
- Capability-based.

Types of Reliability Requirements

Regional reliability standards should be viewed as a portfolio of requirements designed to achieve an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a) **Performance-based** - defines a specific reliability objective or outcome that has a direct, observable effect on the reliability of the Bulk Electric System, i.e. an effect that can be measured using power system data or trends.

[4] Adequate Level of Reliability is available on the NERC website as amended from time to time

[5] The meaning of the phrase "physical difference" will be consistent with FERC's Order, issued September 22, 2004, Granting Request For Clarification regarding Docket No. PL04-5-000, Policy Statement on Matters Related to Bulk Power System Reliability.

[6] Market Principles are available on the NERC website as amended from time to time Link https://www.nerc.com/pa/Stand/Resources/Documents/Market_Principles.pdf#search=market%20principles

[7] ~~For~~ Results-based Standards see http://www.nerc.com/pa/Stand/Resources/Documents/ResultsBasedStandardGuidance.pdf

b) **Risk-based** - defines actions of registered entities that reduce a stated risk to the reliability of the Bulk Electric System and can be measured by evaluating a ~~particular product or outcome~~ resulting from the mandatory requirements.~~required actions~~.

c) **Capability-based** - defines registered entity capabilities needed to perform reliability functions and can be measured by demonstrating that the capability exists within the entity as required.

Each regional standard shall enable or support one or more of the reliability principles[8] as identified in the most recent set posted on the NERC website. Each regional standard shall also be consistent with all of the reliability principles. The intent of the set of NPCC regional standards is to deliver an Adequate Level of Reliability[9] as defined by NERC.

Recognizing that Bulk Electric System reliability and electricity markets are inseparable and mutually interdependent, all regional standards shall be consistent with the most recent set of Market Principles[10] as posted on the NERC website. Consideration of the Market Principles is intended to ensure that regional standards are written such that they achieve their reliability objective without placing undue restrictions or causing adverse impacts on competitive electricity markets.

ELEMENTS OF A REGIONAL STANDARD

A regional standard includes several components designed to work collectively to identify what entities must do to meet their reliability-related obligations as an owner, operator or user of the Bulk Electric System. The components of an NPCC regional standard identified below are based on the NERC Standard Processes Manual (SPM) that was approved by the NERC Board of Trustees at its February 2013 meeting. Future revisions of the NERC SPM will be used to provide guidance at the time of development of an NPCC regional standard if different from the elements listed below and not covered in this Manual.

The only mandatory and enforceable components of a regional standard are the: (1) Applicability, (2) Requirements, and (3) the Effective Dates. The additional components are included in the regional standard for informational purposes, to establish the relevant scope and technical paradigm, and to provide guidance to functional entities concerning how compliance will be assessed by the Compliance Enforcement Authority.

The components of a regional standard may include the following:

Title:	A brief, descriptive phrase identifying the topic of the regional standard.
Number:	An unique identification number assigned in accordance with a published classification system to facilitate tracking and reference to the regional standards.
Purpose:	The reliability outcome achieved through compliance with the requirements of the regional standard.
Applicability:	Identifies which entities are assigned reliability requirements; i.e., the specific functional entities and facilities to which the regional standard applies.
Effective Dates:	Identification of the date or pre-conditions determining when each Requirement becomes effective in each jurisdiction.

[8] Reliability Principles are available on the NERC website as amended from time to time

[9] Adequate Level of Reliability is available on the NERC website as amended from time to time Link: https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Information_Filing_Definition_Adequate_Level_Reliability_20130510.pdf

Commented [RS5]: Quintin Lee is suggesting to copy and paste how NERC"s SPM defines these types.

Commented [RS6]: Quintin Lee' comment: There are several footnotes in the corresponding SPM section that do not appear here should we add them?

Commented [HS7]: Already referenced earlier – do we need this footnote here?

[10] Market Principles are available on the NERC website as amended from time to time

Requirement: An explicit statement that identifies the functional entity responsible, the action or result~~outcome~~ that must be achieved, any conditions necessary to achieving the result~~action or outcome~~, and the reliability-related benefit of the ~~action or~~ outcome. Each requirement shall be a statement for which compliance is mandatory.

Compliance Elements: Elements to aid in the administration of compliance monitoring and enforcement responsibilities.

Measure: Provides identification of the evidence or types of evidence that may demonstrate compliance with the associated requirement.

Violation Risk Factors and Violation Severity Levels: Violation risk factors (VRFs) and violation severity levels (VSLs) are used as factors when determining the size of a penalty or sanction associated with the violation of a requirement in an approved Reliability Standard. Each requirement in each Reliability Standard has an associated VRF and a set of VSLs. VRFs and VSLs are developed by the drafting team, working with NPCC Standards Staff and Compliance Staff, at the same time as the associated Reliability Standard, but are not part of the Reliability Standard. The Board of Directors is responsible for approving VRFs and VSLs.

- Violation Risk Factors
  VRFs identify the potential reliability significance of noncompliance with each requirement. Each requirement is assigned a VRF in accordance with the latest approved set of VRF criteria.
- Violation Severity Levels
  VSLs define the degree to which compliance with a requirement was not achieved. Each requirement shall have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs. Each requirement is assigned one or more VSLs in accordance with the latest approved set of VSL criteria.

Version History: The version history is provided for informational purposes and lists information regarding prior versions of the regional standard.

Variance: As applied to a NPCC regional standard is a Requirement (to be applied in the place of the NPCC region-wide Requirement) that is applicable to a specific geographic area or to a specific set of Registered Entities.

Compliance Enforcement Authority (CEA): The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated regional standard. The Compliance Enforcement Authority will be NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the ERO regional standards.

Commented [RS8]: Quintin Lee's Comment: Since this is the NPCC RSPM, can we just state NPCC here?

Reliability Standard Audit Worksheets (RSAWs)[11] Reliability Standard Audit Worksheets (RSAWs) are developed as companion documents to regional and continent-wide Reliability Standards to facilitate the CEA assessment of a registered entity's compliance with a standard.

[11] While RSAWs are not part of the regional standard, they are developed through collaboration of the drafting team and NPCC Compliance Staff.

Informational Elements: Elements to aid in the implementation of the regional standard.

Application Guidelines:	Guidelines or reference documents to support the implementation of the associated regional standard.
Procedures:	Procedures to support implementation of the associated regional standard.

Commented [HS9]: Perhaps this should nto be here now that NERC is moving guidelines out of standards. We may want to say something about guidelines, but not infer they may be included in the standard document.

IV. REGIONAL STANDARDS DEVELOPMENT PROCESS

1. ROLES IN THE NPCC REGIONAL STANDARD PROCESS

NOMINATION, REVISION, CLARIFICATION, OR RETIREMENT OF A STANDARD:

Any member of NPCC or group within the NPCC region shall be allowed to request that an NPCC regional standard be developed, modified, clarified, or retired. Additionally, any person (organization, company, government agency, individual, etc.) who is directly and materially affected by the reliability of the NPCC Bulk Electric System shall be allowed to request that an NPCC regional standard be developed, modified, clarified, or retired. The following section identifies the process roles in the NPCC regional standards process. Refer to Step 2 STANDARD DEVELOPMENT PROCESS STEPS and FIGURE 1: FLOWCHART OF REGIONAL STANDARDS DEVELOPMENT PROCESS OVERVIEW for the regional standards development process steps and associated flowchart. Refer to Step 3 STANDARD CLARIFICATION PROCESS STEPS and FIGURE 2: FLOWCHART OF REGIONAL STANDARDS CLARIFICATION PROCESS OVERVIEW for the regional standards clarification process steps and associated flowchart.

PROCESS ROLES AND RESPONSIBILITIES

BOARD OF DIRECTORS

The NPCC Board of Directors (Board) shall consider for adoption regional standards, definitions, variances and clarifications and associated implementation plans that have been processed according to the processes identified in this manual.

DRAFTING TEAM

The drafting team (DT) should strive to achieve a portfolio of performance, risk, and capability-based mandatory reliability requirements that support an effective defense-in-depth strategy. The drafting team develops standards-related regional products as directed by the NPCC RSC and within the scope of an approved Regional Standard Authorization Request (RSAR) or a Clarification Request (CR). The product that is developed is typically a new or revised regional standard, but could also be a definition, a reference document, a set of Violation Risk Factors, a set of Violation Severity levels, or the team could be appointed to assist an author in refining a Regional Standard Authorization Request (RSAR). The drafting team also works collaboratively with NPCC Compliance Staff to develop Reliability Standard Audit Worksheets (RSAWs) at the same time regional standards are developed. The drafting team shall remain in place until such time as the NERC Board of Trustees adopts the regional standard.

MANAGER OF RELIABILITY STANDARDS

The NPCC Manager of Reliability Standards has the overall responsibility for managing the NPCC regional standards processes in accordance with this manual. As used herein, the NPCC Manager of Reliability Standards will be the NPCC Manager of Reliability Standards or his/her designee.

NPCC MEMBERS

NPCC members may participate in the comment and ballot periods associated with the development and industry approval of regional standards. The ballot body is comprised of all

entities or individuals that qualify for one of the stakeholder sectors within NPCC as stated in the most recently approved NPCC Bylaws. All General and Full Members of NPCC can participate in the balloting of regional standards. Any entity or person, including non-NPCC members, may submit comments during the open process comment periods for standards.

NON-NPCC MEMBERS

Any entity or person that is neither a General nor Full Member of NPCC is not eligible to participate in the ballot body voting on a regional standard. However, any entity or person, including non-NPCC members, may submit comments during the open process comment periods for standards. Subject Matter Experts (SMEs), regardless of NPCC membership status, are encouraged to participate in comment periods for regional standards.

NPCC STANDARDS STAFF

The Standards Staff is responsible for assisting the NPCC Manager of Reliability Standards and the RSC in administering the NPCC regional standards processes in accordance with this manual.

NPCC COMMITTEES, TASK FORCES AND WORKING GROUPS

The Committees, Task Forces and Working Groups within NPCC serve an active role in the standards process. Activities performed by these groups include, but are not limited to, the following:

- Identify the need for new or modified regional standards
- Initiate NPCC Standards actions by developing Regional Standard Authorization Requests (RSARs)
- Develop comments (views~~, and~~ objections and suggestions) to standards actions
- Participate in NPCC Standard drafting
- Dispensation of Clarification Requests (CRs)
- Provide technical oversight in response to changing industry conditions and ERO Requirements
- Conduct Field Tests, as required

REGIONAL STANDARDS COMMITTEE (RSC)

The NPCC Regional Standards Committee (RSC), a committee of the NPCC Board of Directors, is charged with oversight of all drafting team activities and managing the NPCC regional standards development process in accordance with this manual.

The RSC is responsible for maintenance of the Regional Standard Processes Manual (RSPM), including the endorsement of RSPM revisions for NPCC Board review and approval.

RELIABILITY COORDINATING COMMITTEE (RCC)

The Reliability Coordinating Committee (RCC) supports the standards development process through the assignment of NPCC Task Forces to serve as technical resources for: (1) staffing drafting teams, and (2) performing a technical advisory role in the regional standards process through comments, recommendations and technical justifications.

REQUESTER

Any individual representing an organization (entity, company, government agency, etc.) that is directly and materially affected by the reliability of the Bulk Electric System within the NPCC

geographical area may request a regional standard be developed or an existing regional standard be modified, clarified, or deleted.

QUALITY REVIEW TEAM

The NPCC Standards Staff shall coordinate a quality review of the "final draft" of the regional standard, implementation plan, VRFs and VSLs to assess whether the documents are within the scope of the associated RSAR, whether the regional standard is clear and enforceable as written and the VRFs and VSLs are developed according to NERC and FERC guidelines. The Quality Review Team may be comprised of legal and compliance representatives, a technical writer, and NPCC Standards Staff. It will not involve individuals who participated on the drafting team of the standard undergoing the Quality Review.

2. STANDARD DEVELOPMENT PROCESS STEPS

STEP 2.1: REGIONAL STANDARDS AUTHORIZATION REQUEST TO DEVELOP, MODIFY OR RETIRE

A Regional Standard Authorization Request[12] (RSAR) is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified regional standards or the benefit of retiring one or more approved regional standards.

A RSAR shall be used to seek approval and initiate the development, modification or retirement of a NPCC regional standard. A RSAR is not used to seek a Clarification Request (CR) of a NPCC regional standard. The initiation and handling of a CR is covered in Step 3 STANDARD CLARIFICATION PROCESS STEPS, of this manual.

Any individual representing an organization which is directly or materially impacted by the operation of the Bulk Electric System within the geographical footprint of NPCC may request, via a submittal of a RSAR to the NPCC Manager of Reliability Standards, the development, modification, or deletion of a NPCC regional standard. The individual completing the form is referred to herein as the Requester.

STEP 2.1.A. REQUESTER ACTIONS

Note: The NPCC Manager of Reliability Standards will assist the Requester, as necessary, to ensure all required information is submitted on the RSAR.

The Requester shall complete an RSAR form in accordance with the guidance provided in APPENDIX A: RSAR COMPLETION GUIDELINES.

The Requester shall submit the completed RSAR to the NPCC Manager of Reliability Standards, via npccstandard@npcc.org, for processing.

STEP 2.1.B. NPCC MANAGER OF RELIABILITY STANDARDS ACTIONS

The NPCC Manager of Reliability Standards shall review the submitted RSAR and verify that the submitted form has been adequately completed. Within fifteen (15) calendar days[13] of receipt of the submitted RSAR, the NPCC Manager of Reliability Standards will electronically acknowledge

[12] The RSAR is located on the NPCC website under Standards – Regional Standards General

[13] Time periods specified in this manual may be extended as deemed appropriate by NPCC Staff. When business days are specified, this provision could be used to take into account differing Canadian and US holiday schedules. When calendar days are specified, this provision could be used to take into account due dates that fall on a weekend.

receipt of the RSAR. If, at that time, the NPCC Manager of Reliability Standards finds the RSAR to be deficient, the Requester will be contacted to determine how to proceed.

Within ten (10) calendar days of the receipt of an adequately completed RSAR, the NPCC Manager of Reliability Standards shall forward the properly completed RSAR to the NPCC Regional Standards Committee (RSC) for its review and processing. Included in the transmittal of the RSAR to the RSC, the NPCC Manager of Reliability Standards shall include a statement indicating the applicability of the NPCC Cost Effectiveness Analysis Procedure (CEAP) for the proposed change.

STEP 2.1.C. NPCC REGIONAL STANDARDS COMMITTEE (RSC) ACTIONS

Note: The RSC shall meet to review all pending RSARs. The frequency of this review process will depend on workload, but in no case shall a properly completed[1] RSAR wait for RSC action more than 60 calendar days from the date of receipt by the RSC.

The RSC shall review the RSAR and take one of the following actions:

- Remand the RSAR back to the NPCC Manager of Reliability Standards for additional work. In this case, the NPCC Manager of Reliability Standards shall work with the Requester to provide additional information or clarification for the RSAR as specified by the RSC.
- Reject the RSAR. In this case, the RSC will provide its determination to the NPCC Manager of Reliability Standards, who will then provide a written explanation for rejection to the Requester within ten (10) calendar days of the rejection decision.

Note: Before the RSC can accept an RSAR for a new or modified standard the applicable CEAP process steps shall be completed.

- Accept the RSAR.
  - If a new or modified standard has been authorized, within ten (10) calendar days of the authorization the NPCC Manager of Reliability Standards shall: 1) post notification on the NPCC website of the intent to develop or modify a regional standard; 2) notify the ERO for processing in accordance with its process, as applicable; and 3) notify the Requester of the acceptance of the RSAR.
  - If the retirement of an existing regional standard has been authorized, within ten (10) calendar days of the authorization the NPCC Manager of Reliability Standards shall: 1) post notification on the NPCC website of the intent to retire an existing regional standard; 2) notify the ERO for processing in accordance with its process, as applicable; and 3) notify the Requester of the acceptance of the RSAR. The process to retire an existing regional standard is included in Step 6 RETIREMENT OF AN APPROVED NPCC REGIONAL STANDARD.

STEP 2.2: FORMATION OF DRAFTING TEAM FOR NEW OR MODIFIED STANDARD

A RSAR that has been accepted by the RSC shall, within ten (10) calendar days of the acceptance of the RSAR, be submitted by the NPCC Manager of Reliability Standards to the NPCC Reliability Coordinating Committee (RCC). The RCC shall, within sixty (60) calendar days, assign the development of the regional standard to a NPCC Task Force, and notify the NPCC Manager of Reliability Standards of its decision within ten (10) calendar days.

Commented [HS10]: Do we need to say more about what constitutes a properly completed RSAR here? Perhaps a footnote… Properly completed RSAR contains the following information. Etc. Etc.

Or just a reference to Appendix A where the RSAR instructions reside.

Commented [HS11]: What if there is no Task Froze with the requisite scope or skills for a regional standard? I ma thinking of DER here. Should there be an ability to create a Task force specifically for the purpose?

[1] A properly completed RSAR is one which has fulfilled all the expectations outlined in Appendix A.

After receipt of the notification of drafting team assignment, the NPCC Manager of Reliability Standards shall oversee solicitation and recommendation of a list of additional qualified [14] candidates over and above the appropriate NPCC Task Force members, for appointment to the drafting team. The Requester and a NPCC Compliance Staff person will be included on the drafting team. Within sixty (60) calendar days of the drafting team assignment notification from the RCC, the NPCC Manager of Reliability Standards shall submit the list of the entire drafting team membership to the RSC for acceptance. The RSC may accept the recommendations of the NPCC Manager of Reliability Standards as presented or revise the recommendations as necessary.

Upon acceptance of the drafting team slate, the RSC shall provide a target date on which the drafting team is expected to have ready a completed draft regional standard and associated supporting documentation available for consideration by the NPCC membership. Additionally, the RSC shall provide the drafting team with any preliminary development products including, but not limited to, a draft standard, comments, and related white papers.

The RSC shall designate one of its members to actively monitor and assist NPCC staff in the oversight of drafting team milestones and deadlines, and extend or expedite milestones and deadlines, as appropriate, acting as a liaison between the drafting team and the RSC to help resolving any issues.

STEP 2.3: DEVELOPMENT OF A REGIONAL STANDARD AND ASSOCIATED DOCUMENTS

Prior to beginning work on the development of a new or revised regional standard and the associated supporting documentation, the drafting team should develop a work plan for completing the regional standard development work, including the establishment of milestones for completing critical elements of the work in sufficient detail to ensure that the drafting team will meet the target date established by the RSC, or the drafting team shall propose an alternative date. This work plan must be submitted to the RSC for its concurrence. When a drafting team begins its work, it shall regularly (at least quarterly) report progress against that aforementioned work plan to the NPCC Manager of Reliability Standards for presentation to the RSC.

Note: During the regional standards development, the drafting team will deliberate on whether the requirements in the regional standard are ~~developed enough~~ adequate for the purpose off~~to begin~~ the Cost Effectiveness Analysis (CEA) and the ~~of the~~ NPCC Cost Effectiveness Analysis Procedure (CEAP). When appropriate, the drafting team shall request that the RSC initiate the second phase (CEA) of the CEAP process.

The drafting team shall create and manage its work structure (e.g., sub-teams) and meeting schedule (face-to-face as well as electronic meetings), as necessary, to meet the milestone dates and project deliverables outlined in the work plan.

The work products of the drafting team should consist of the following

- A draft regional standard consistent with the RSAR on which it was based
- An implementation plan, including the nature, extent and duration of field-testing, if any
- Identification of any existing regional standard and NPCC criteria that will be deleted, in part or whole, or otherwise impacted by the implementation of the draft regional standard

[14] Refer to Appendix B: Selection of Drafting Team Members

- Technical reports, white papers and/or work papers that provide technical justification for the draft regional standard under consideration
- Reliability Standard Audit Worksheet (RSAW) collaboratively developed by the drafting team and NPCC Compliance Staff

Any proposed changes to definitions in existing regional standards should be sent to the appropriate Task Force (TF) for consideration of the impact to the standard. If necessary, the TF can produce an RSAR.

NPCC Standards Staff can assist in the drafting of the regional standard including compliance measures, process and elements. The drafting of measures and compliance administration aspects of the standard will be coordinated with the NPCC Compliance Staff.

The drafting team shall submit the initial and subsequent interim drafts of the regional standard and associated documents to the NPCC Manager of Reliability Standards to obtain RSC concurrence to post documents for comment.

STEP 2.4: POSTING FOR COMMENT PERIOD AND RESOLUTION OF COMMENTS

Note:	*There are no limits to the number of public comment periods and ballots that can be conducted to result in a regional standard that is clear and enforceable, and achieves a quorum and sufficient affirmative votes for approval.*

STEP 2.4.A. COMMENT PERIOD

Note:	*For Final Comment Period skip this step and proceed to* STEP 2.4.B. FINAL COMMENT PERIOD.

As authorized by the RSC, the NPCC Manager of Reliability Standards shall post the draft of the regional standard on the NPCC website, along with a draft implementation plan and available supporting documents, for a forty-five (45) calendar day comment period. The NPCC Manager of Reliability Standards shall also notify NERC to process the draft document in accordance with NERC's regional standards review procedure, as applicable.

Following the conclusion of the NPCC comment period, the NPCC Manager of Reliability Standards will assemble the comments on the draft regional standard and associated documents and provide all comments to the drafting team for consideration.

Within thirty (30) calendar days of the conclusion of the comment period the drafting team shall convene and consider changes to the draft Standard, the implementation plan and/or supporting technical documents based upon comments received. All submitted comments shall be addressed, and each commenter shall be advised of the disposition, with reasons, of their comments. The NPCC Manager of Reliability Standards shall publicly post all of the drafting team's responses to stakeholder comments on the NPCC website.

Based on the comments received, the drafting team may elect to:

- Return to STEP 2.3: DEVELOPMENT OF A REGIONAL STANDARD AND ASSOCIATED DOCUMENTS to revise the draft regional standard, the implementation plan and/or supporting technical documents.
- Recommend that the RSC authorize Field Testing of the draft regional standard. Upon completion of the Field Test, return to STEP 2.3: DEVELOPMENT OF A REGIONAL STANDARD

AND ASSOCIATED DOCUMENTS to revise the draft regional standard based on insights learned during the Field Test.

- Obtain RSC concurrence to post documents for Final Comment Period and request that the RSC initiate the second phase (CEA) of the CEAP process

STEP 2.4.B. FINAL COMMENT PERIOD

The NPCC Standards Staff shall coordinate a Quality Review of "final draft" of the regional standard, implementation plan, VRFs and VSLs to assess whether the documents are within the scope of the associated RSAR, whether the regional standard is clear and enforceable as written and the VRFs and VSLs are developed according to NERC and FERC guidelines. Upon Completion of the Quality Review, including resolution of comments, the drafting team shall submit the regional standard to the NPCC Manager of Reliability Standards to obtain RSC concurrence to post these documents for comment.

As authorized by the RSC, the NPCC Standards Staff shall post the "final draft" of the regional standard on the NPCC website, along with the implementation plan, supporting documents and the Cost Effectiveness Analysis (CEA) survey[15] for a forty-five (45) calendar day comment period. NPCC Standards Staff shall also notify NERC to process the proposed final document in accordance with NERC's regional standards review procedure, as applicable.

Following the conclusion of the NPCC comment period, the NPCC Manager of Reliability Standards will assemble the comments on the posted regional standard and associated documents and provide all comments to the drafting team for consideration.

In addition, the RSC, pursuant with the requirements of the Cost Effectiveness Analysis Procedure (CEAP), will use the responses to the posted CEA survey to develop a recommendation based on the cost effectiveness of the proposed regional standard.

The NPCC Task Forces (TFs) or Working Groups (WGs) may develop recommendations for submittal to the RSC. Following the RSC deliberations to determine a course of action, the RSC will communicate to the drafting team to:

- Return to STEP 2.3: DEVELOPMENT OF A REGIONAL STANDARD AND ASSOCIATED DOCUMENTS to revise the Standard to address the results of the CEAP
- Accept the Standard "as is" to move forward through the remainder of the process
- Hold the Standard in abeyance until such time as additional guidance can be provided regarding whether or how to continue
- Decide not to pursue the development of certain requirements or the entire Standard due to cost effectiveness considerations

Upon Completion of the final comment period the drafting team shall submit the proposed regional standard, along with any supporting materials, consideration of comments and field test results, to the NPCC Manager of Reliability Standards to obtain RSC concurrence to post the regional standard for ballot and concurrently provide an information copy to the RCC.

[15] In accordance to the Cost Effectiveness Analysis Procedure (CEAP) the Cost Effectiveness Analysis (CEA) survey may be assigned directly to NPCC Task Forces (TFs) or Working Groups (WGs) in addition to the posting process.

The NPCC Manager of Reliability Standards shall also publicly post all of the drafting team's responses to stakeholder comments on the NPCC website.

STEP 2.5: POSTING FOR BALLOT PERIOD IN THE OPEN PROCESS

Note: There are no limits to the number of public comment periods and ballots that can be conducted to result in a regional standard that is clear and enforceable, and achieves a quorum and sufficient affirmative votes for approval.

Commented [HS12]: Is it clear who decides when enough is enough?

As authorized by the RSC, the NPCC Manager of Reliability Standards shall post the proposed regional standard on the NPCC website, along with supporting documentation [16] (e.g., implementation plan, consideration of comments, technical reports, white papers and any field test results), for a thirty (30) day pre-ballot review period and a subsequent ten (10) day ballot period. The ten (10) day ballot period will commence immediately following the pre-ballot review period. In the event that a quorum exists for purposes of an electronic vote but the ballot purpose has not been resolved, NPCC may continue to solicit additional responses in order to resolve the matter by electronic voting. In the event that quorum has not been achieved for purposes of an electronic vote, NPCC may continue to solicit electronic ballots, including abstentions, to obtain quorum and resolve the matter.

At the time the regional standard is posted for ballot, the NPCC Manager of Reliability Standards shall also notify NERC to process the proposed regional standard in accordance with NERC's regional standards review procedure, as applicable.

During the ballot period, the NPCC Members of the ballot body can cast their vote as follows:

- Affirmative, with or without comments
- Negative with comments
- Abstain

In accordance with the NPCC Bylaws, a quorum and receipt of a two-thirds (2/3) affirmative majority of the weighted sector votes is required for a ballot to pass.

The NPCC Manager of Reliability Standards shall post the final outcome of the ballot process on the NPCC website.

STEP 2.5.A. BALLOT DOES NOT RECEIVE 2/3 AFFIRMATIVE VOTE

If a ballot fails to achieve the 2/3 majority vote the NPCC Manager of Reliability Standards may:

- Direct the drafting team to respond to ballot comments and return to STEP 2.5: POSTING FOR BALLOT PERIOD IN THE OPEN PROCESS to re-ballot the regional standard. The consideration of comments from prior ballot will be included with the re-posting.
- Return to STEP 2.3: DEVELOPMENT OF A REGIONAL STANDARD AND ASSOCIATED DOCUMENTS to revise the regional standard to address the comments received.
- Pursue the discontinuance of the regional standard development by soliciting the Requester to withdraw the RSAR or by soliciting the RSC to reject the RSAR pursuant with STEP 2.1.C. NPCC REGIONAL STANDARDS COMMITTEE (RSC) ACTIONS. The NPCC Manager of

[16] The ballot posting is for the regional standard, definition, variance or clarification. Supporting documentation is included for information only and is not balloted.

Reliability Standards, in the event of a discontinuance of the development of a regional standard, shall post a notice of the discontinuance and will post and archive all comments submitted during the process for future consideration, if required. The NPCC Manager of Reliability Standards will also notify NERC to process the proposed regional standard in accordance with NERC's regional standards review procedure, as applicable.

STEP 2.5.B. BALLOT RECEIVES ≥ TWO-THIRDS (2/3) AFFIRMATIVE VOTE

A ballot that achieved two-thirds or greater affirmative vote has successfully passed. However, negative votes with comments should still be reconciled. If there is at least one negative vote with comments proceed to STEP 2.5.B.1 APPROVED BALLOT WITH "NEGATIVE VOTE WITH COMMENT". If there was not any negative vote with comments proceed to STEP 2.5.B.2 APPROVED BALLOT WITHOUT "NEGATIVE VOTE WITH COMMENT".

STEP 2.5.B.1 APPROVED BALLOT WITH "NEGATIVE VOTE WITH COMMENT"

Following the conclusion of the NPCC ballot period, the NPCC Manager of Reliability Standards will assemble the comments on the posted regional standard and provide all comments to the drafting team for consideration. The drafting team shall review all negative votes with comments and elect to:

- Recommend to the RSC to accept the regional standard "as is" and seek RSC endorsement to move forward through the remainder of the process. Upon receiving RSC endorsement to proceed, the regional standard and associated documents, approved by the NPCC ballot body, shall be forwarded by the Assistant Vice President Standards to the NPCC Board of Directors for final Regional approval. If comments that were received during balloting should be considered in future revisions to the regional standard then the NPCC Manager of Reliability Standards should log comments in an issues database.
- Return to STEP 2.3: DEVELOPMENT OF A REGIONAL STANDARD AND ASSOCIATED DOCUMENTS to revise the regional standard to address the comments received.
- Respond to ballot comments and recommend to the RSC endorse the return to STEP 2.5: POSTING FOR BALLOT PERIOD IN THE OPEN PROCESS to re-ballot the regional standard. The NPCC Manager of Reliability Standards should include the consideration of comments from the prior ballot with the re-posting.

STEP 2.5.B.2 APPROVED BALLOT WITHOUT "NEGATIVE VOTE WITH COMMENT"

Regional standard and associated documents, approved by the NPCC ballot body, shall be forwarded by the Assistant Vice President Standards to the NPCC Board of Directors for final Regional approval.

STEP 2.6: NPCC BOARD OF DIRECTORS APPROVAL

Following approval by the NPCC Members, regional standards require review and approval by the NPCC Board of Directors. The NPCC Board of Directors may take the following actions:

- Approve the regional standard as presented.
- Approve the regional standard with comments to incorporate non-substantive revisions. [The NPCC Board of Directors may not make substantive revisions to the standard.]
- Remand the regional standard back to the RSC and the drafting team to address their concerns. The RSC / drafting team can address the BOD comments and re-submit for BOD

approval or return to STEP 2.3: DEVELOPMENT OF A REGIONAL STANDARD AND ASSOCIATED DOCUMENTS to revise the regional standard to address the comments received.

STEP 2.7: NERC BOARD OF TRUSTEES SUBMITTAL

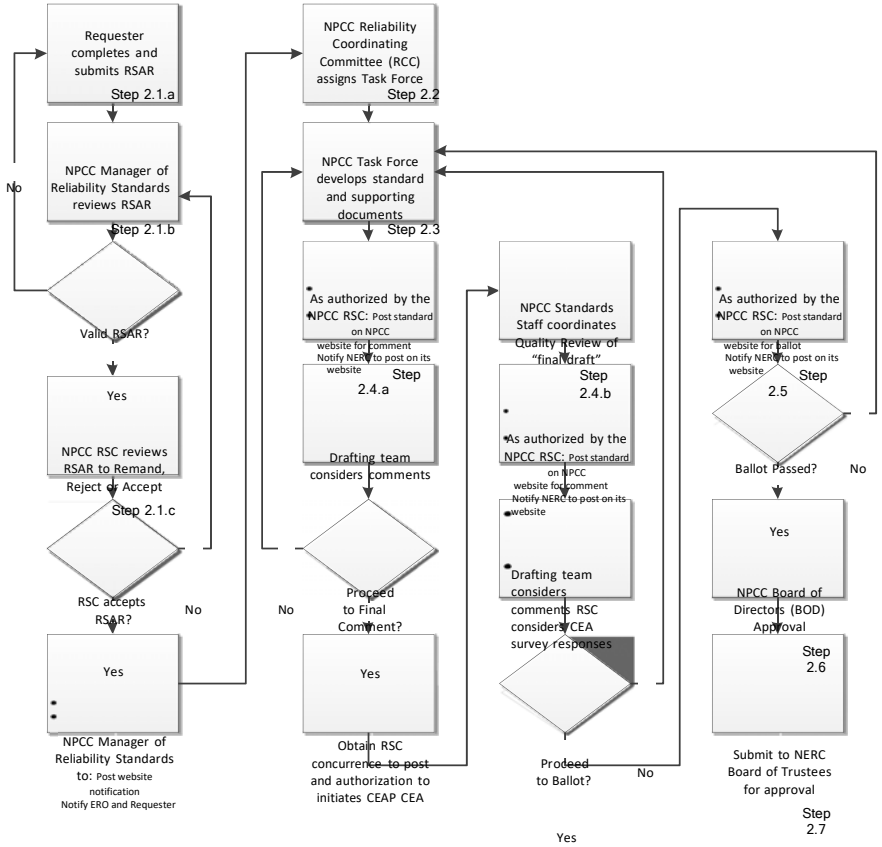
Upon approval by the NPCC Board of Directors, the NPCC Manager of Reliability Standards shall submit the regional standard to NERC, as the Electric Reliability Organization, for approval and subsequent filing with FERC and the applicable Canadian Provincial regulatory and/or governmental authorities for adoption.

STEP 2.8: IMPLEMENTATION OF AN NPCC REGIONAL STANDARD

Following the approval of an NPCC regional standard by FERC and the applicable Canadian Provincial regulatory and/or governmental authorities, all users, owners, and operators of the Bulk Electric System in the NPCC geographic area are required to comply with the standard as of its enforcement date.

ERO approved Reliability Standards (both continent-wide and regional) are included in both the NERC and NPCC Compliance Monitoring and Enforcement Programs (CMEPs).

FIGURE 1: FLOWCHART OF REGIONAL STANDARDS DEVELOPMENT PROCESS OVERVIEW



3. STANDARD CLARIFICATION PROCESS STEPS

This section applies to NPCC regional standards that have been approved[17] and are currently enforceable or have a future enforcement date. A clarification request is not permitted for regional standards under development. For regional standards under development, an explanation of a requirement or its meaning can be sought during a comment period. Refer to Step 2, STANDARD DEVELOPMENT PROCESS STEPS of this manual for details on the comment process for a standard under development.

STEP 3.1: REGIONAL STANDARDS CLARIFICATION REQUEST (CR)

Any member of NPCC or group within the NPCC region shall be allowed to submit a Clarification Request (CR) for a NPCC regional standard.

Additionally, any person (organization, company, government agency, individual, etc.) who is directly and materially affected by the reliability of the NPCC Bulk Electric System shall be allowed to submit a Clarification Request (CR) for a NPCC regional standard.

> *Note: A valid Clarification Request is one that seeks additional clarity about one or more requirements in an approved regional standard, but does not request approval as to how to comply with any requirements of the standard.*

The Requester should submit a Clarification Request[18] (CR) for a NPCC regional standard directly to the NPCC Manager of Reliability Standards, via npccstandard@npcc.org, for processing. Alternatively, the Requester can submit a Request for Interpretation (RFI) of an NPCC regional standard under the NERC process for developing an interpretation[19] to the NERC Reliability Standards Staff explaining the clarification required, the specific circumstances surrounding the request, and the impact of not having the clarification provided. A copy of the completed RFI form should also be sent to the NPCC Manager of Reliability Standards.

NERC Reliability Standards Staff will refer the RFI to NPCC and delegate its resolution to NPCC. NPCC will process the NERC delegation pursuant with the NPCC Clarification Request (CR) process described herein.

STEP 3.2: REVIEW AND VALIDATION OF CLARIFICATION REQUEST (CR)

Upon receipt of a Clarification Request (CR) for an NPCC regional standard, the NPCC Manager of Reliability Standards shall review the CR to determine whether:

- It meets the requirements for a valid Clarification Request
- A compliance process or approach could be used in lieu of a clarification

The NPCC Manager of Reliability Standards will utilize, as necessary, the NPCC Standards Staff, NPCC Compliance and Legal Staffs when determining the validity of the CR. Based on this review, the NPCC Manager of Reliability Standards will recommend to the RSC whether to accept or reject the CR. The recommendation to the RSC should be made within thirty (30) calendar days of the receipt of the CR.

[17] Approval is granted by FERC and the Canadian Provincial regulatory and/or governmental authorities, as applicable.
[18] The NPCC Clarification Request form is included as Appendix D
[19] The *Request for Interpretation* form is posted under Resource Documents on the NERC Standards webpage.

The following examples identify situations that may warrant a recommendation from the NPCC Manager of Reliability Standards to reject the CR:

- Requests approval of a particular compliance approach
- Identifies a gap or perceived weakness in the approved regional standard (Requester should be redirected to initiate a RSAR rather than a CR)
- Where an issue can be addressed by an active (regional or continent-wide) standard drafting team
- Where an issue can be better addressed by a compliance process or approach
- Where it requests clarification of any element of a regional standard other than a requirement
- Where a question has already been addressed in the record
- Where the clarification identifies an issue and proposes the development of a new or modified regional or continent-wide standard (such issues should be addressed via submission of a RSAR or SAR)
- Where a clarification seeks to expand the scope of a regional standard
- Where the requirement of the regional standard is clear

Commented [RS13]: Quintin Lee's Comment: Does SAR need to be included here?

STEP 3.3: NPCC REGIONAL STANDARDS COMMITTEE (RSC) ACTIONS

The RSC shall review the CR along with the recommendation from the NPCC Manager of Reliability Standards and take one of the following actions:

- Reject the CR. In this case, the RSC will provide its determination to the NPCC Manager of Reliability Standards, who will then provide a written explanation for rejection to the CR to the entity requesting the clarification within ten (10) calendar days of the decision to reject.
- Accept the CR. In this case, the RSC will provide its determination to the NPCC Manager of Reliability Standards, who will then: 1) post notification on the NPCC website of the intent to develop a clarification; 2) notify the NPCC Reliability Coordinating Committee (RCC) of the need to assign the resolution of the CR to one or more Task Forces (if more than one Task Force is assigned, one of them shall be assigned the lead role); and 3) notify the Requester of the acceptance of the CR. The notifications shall be made within ten (10) calendar days of the acceptance of the CR.

STEP 3.4: FORMATION OF DRAFTING TEAM FOR RESPONSE TO CR

A CR that has been accepted by the RSC shall be assigned by the RCC to the responsible NPCC Task Force to make up the clarification drafting team (CDT) and develop the CR response.

STEP 3.5: DEVELOPMENT OF RESPONSE TO CR

> *Note: A valid clarification response provides additional clarity about one or more requirements, but does not expand on any requirement and does not explain how to comply with any requirement.*

Within sixty (60) calendar days from the receipt of being assigned to respond to a CR, the CDT shall submit a proposed clarification response to the NPCC Manager of Reliability Standards. Upon receipt of the proposed clarification response from the CDT, the NPCC Manager of

Reliability Standards shall present the response to the RSC to obtain concurrence to post the proposed response for comment.

Along with the proposed clarification response, the drafting team shall also develop and submit a set of questions to be included in the comment form, for approval by the RSC.

If the RSC concurrence is not received, the drafting team will continue to refine the clarification response.

Note: There are no limits to the number of public comment periods that can be conducted to result in a clear and concise clarification of a regional standard requirement.

STEP 3.6: POSTING CR FOR COMMENT PERIOD AND RESOLUTION OF COMMENTS

As authorized by the RSC, the NPCC Manager of Reliability Standards shall post the proposed clarification response on the NPCC website for a forty-five (45) calendar day comment period.

Following the conclusion of the NPCC comment period, the NPCC Manager of Reliability Standards will assemble the comments on the proposed clarification response and provide all comments to the drafting team for consideration.

Within thirty (30) calendar days of the conclusion of the comment period the drafting team shall convene and consider changes to the proposed clarification response based upon comments received. All submitted comments shall be addressed, which may be in the form of a summary response addressing each of the issues raised in comments received. The NPCC Manager of Reliability Standards shall publicly post all of the drafting team's responses to stakeholder comments on the NPCC website.

Based on the comments received, the drafting team may elect to:

- Return to STEP 3.5: DEVELOPMENT OF RESPONSE TO CR to revise the proposed clarification response.
- Accept the proposed clarification response "as is" to move forward through the remainder of the process.

Upon acceptance of the proposed clarification response "as is," the drafting team shall submit the proposed clarification response to the NPCC Manager of Reliability Standards to obtain RSC endorsement to the submitted CR response.

STEP 3.7: REGIONAL STANDARDS COMMITTEE APPROVAL OF CR

Upon receipt of the CR response from the NPCC Manager of Reliability Standards, the RSC shall elect to:

- Endorse the proposed clarification response and direct the NPCC Assistant Vice President Standards to forward the CR to the NPCC Board of Directors for final Regional approval; or
- Direct the drafting team to return to STEP 3.5: DEVELOPMENT OF RESPONSE TO CR to revise the proposed clarification response

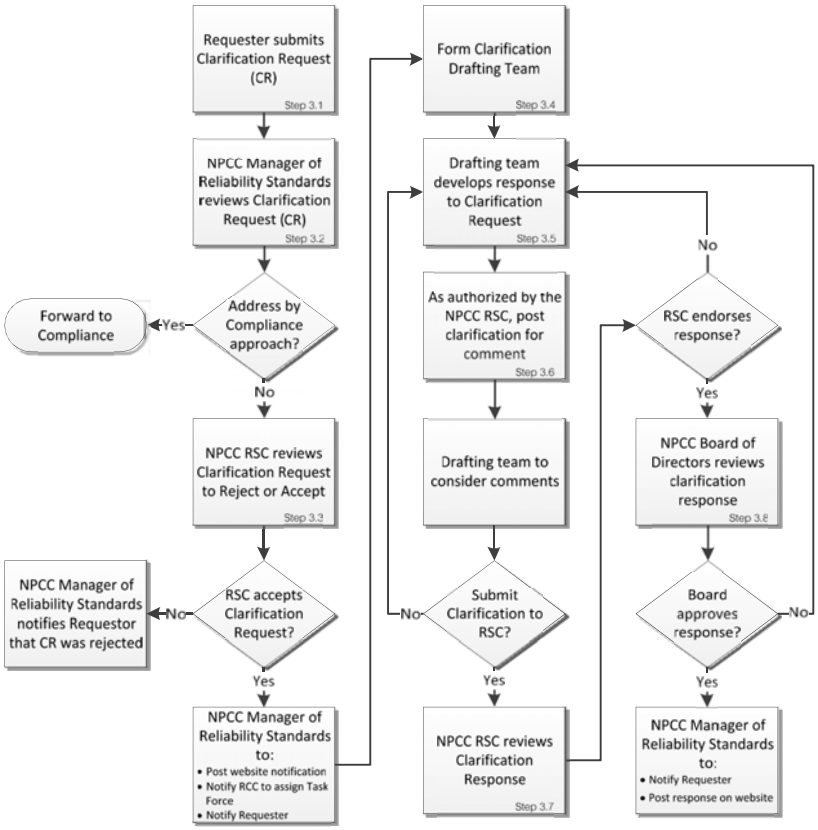
STEP 3.8: NPCC BOARD OF DIRECTORS APPROVAL OF CR

Following endorsement by the RSC, clarification responses require review and approval by the NPCC Board of Directors. The NPCC Board of Directors may take the following actions:

- Approve the clarification response as presented
- Approve the clarification response with comments to incorporate non-substantive revisions. [The NPCC Board of Directors may not make substantive revisions to the clarification response.]
- Remand the clarification response back to the RSC and the drafting team to address their concerns

Upon receipt of Board approval, the NPCC Manager of Reliability Standards shall notify the Requestor and post the approved clarification on the NPCC website.

FIGURE 2: FLOWCHART OF REGIONAL STANDARDS CLARIFICATION PROCESS OVERVIEW



4. DISCONTINUANCE OF REGIONAL STANDARD DEVELOPMENT

The term "discontinuance" as used herein refers to terminating the standard development process after RSAR approval but prior to posting a regional standard for industry ballot. From time to time the need or rationale for a regional standard may change thereby necessitating the curtailment

of the regional standard development. Upon notification or determination that a regional standard under development should be considered for discontinuance due to a perceived change in the need for the standard, the NPCC Manager of Reliability Standards will submit the recommendation for discontinuance to the RSC for approval.

5. WITHDRAWAL OF A REGIONAL STANDARD PENDING APPROVAL

The term "withdrawal" as used herein, refers to the revocation of a request for approval of a regional standard, variance, clarification or definition that has been approved by the NPCC Board of Directors and has not been filed with Applicable Governmental Authorities or has been filed but not yet approved by Applicable Governmental Authorities. The RSC may withdraw a regional standard, variance, clarification or definition for good cause subject to approval by the NPCC Board of Directors. Upon approval by the NPCC Board of Directors, the NPCC Manager of Reliability Standards will notify NERC Staff to petition the Applicable Governmental Authorities, as necessary, to allow for withdrawal in the case that the regional standard has been filed.

6. RETIREMENT OF AN APPROVED NPCC REGIONAL STANDARD

The term "retirement" refers to the discontinuation of a regional standard in whole, certain requirements within a regional standard, a variance, clarification or definition that: 1) has been approved by Applicable Governmental Authorities and 2) is not being superseded by or merged into a new or revised regional standard, clarification or definition.

Upon identification of a need for retirement, an RSAR containing the proposal of the retirement will be handled in accordance with the STEP 2.1: REGIONAL STANDARDS AUTHORIZATION REQUEST TO DEVELOP, MODIFY OR RETIRE. The proposal shall include the rationale for the retirement and a statement regarding the impact of retirement on the reliability of the Bulk Electric System. Upon approval by the NPCC Members and the NPCC Board of Directors, the NPCC Manager of Reliability Standards shall submit the request for retirement to NERC, as the Electric Reliability Organization, for approval and to subsequently petition the Applicable Governmental Authorities to allow for retirement.

7. APPROVAL OF PROCESS WAIVER

While it is NPCC's intent to adhere to this manual under normal circumstances, NPCC may need to develop a new or modified regional standard, implementation plan, variance, clarification or definition under extenuating circumstances. Extenuating circumstances may include, but not be limited to, specific time constraint imposed by a regulatory body and urgent reliability issue that requires expedited handling outside of the normal regional Reliability Standards process.

The RSC, by two-thirds (2/3) majority vote, may waive any of the provisions contained in this manual for good cause shown, but limited to the following circumstances:

- Where necessary to meet regulatory deadlines
- Where necessary to address an urgent reliability issue identified by regulatory and/or governmental authorities, including response to national emergency declared by the United States or Canadian government that involves the reliability of the Bulk Electric System or cyber-attack on the Bulk Electric System
- Where necessary to meet deadlines imposed by the NPCC Board of Directors

- Where the RSC determines that a revision to a proposed regional standard, implementation plan, variance, clarification or definition has already been vetted by the industry through the standards development process or is so insubstantial that developing the revision through the processes contained in this manual will add significant time delay without any corresponding benefit.

In no circumstances shall this provision be used to modify the requirements for achieving quorum or the voting requirements for approval of a standard.

A waiver request may be submitted to the RSC by any entity or individual, including NPCC committees or subgroups and NPCC Standards Staff. Prior to consideration of any waiver request, the NPCC Manager of Reliability Standards must provide notification to stakeholders at least five (5) business days prior to RSC consideration and action. Posting the waiver request on the NPCC website satisfies the notification provision.

Action on the waiver request will be included in the minutes of the RSC. Following the approval of the RSC to waive any provision of the regional Reliability Standards process, the Assistant Vice President Standards shall report the exercise of this waiver provision to the NPCC Board of Directors prior to adoption of the related Reliability Standard, clarification, definition or variance. Actions taken pursuant to an approved waiver request will be posted on the NPCC Standards webpage.

8. Process For Correcting Errata

From time to time, an error in printing or writing, such as misspellings, omissions, and other typographical errors. may be discovered in a regional standard after it has received final ballot approval by the NPCC ballot body. Such errors may be corrected by the RSC without re-balloting if the RSC as a whole by ballot agrees that the correction of the error does not change the scope, applicability or intent of the associated regional standard, and agrees that the correction has no material impact on the compliance obligations of registered entities. ~~end users of the regional standard~~.

If the regional standard containing errata is pending approval by the NPCC Board of Directors, the corrected regional standard shall be presented to the NPCC Board for approval in lieu of the regional standard approved by the NPCC ballot body.

If a regional standard containing errata had received prior approval by the NPCC Board of Directors, the corrected regional standard shall be presented to the NPCC Board for approval. Upon approval by the Board, the corrected regional standard will be filed for approval by NERC.

The NPCC Board of Directors has resolved to concurrently approve any errata approved by the RSC associated with a regional standard that has received prior approval by the NPCC Board.

9. Appeals

Persons who have directly and materially affected interests and who have been or will be adversely affected by any substantive or procedural action or inaction related to the approval, revision, reaffirmation, or withdrawal of a regional standard (appellant) shall have the right to appeal. This appeals process applies only to the regional standards process as defined in this manual.

The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made within thirty (30) calendar days of the date of the action purported to cause the adverse effect, except appeals for inaction, which may be made at any time. In all cases, the request for appeal must be made prior to the next step in the process.

Commented [HS14]: I think we need to discuss what constitutor's Errata.

errors in printing or writing, such as misspellings, omissions, and other typographical errors.

The final decisions of any appeal shall be documented in writing and made public.

The appeals process provides two levels, with the goal of expeditiously resolving the issue to the satisfaction of the participants:

LEVEL 1 APPEAL

Level 1 is the required first step in the appeals process. The appellant submits a complaint in writing to the NPCC Manager of Reliability Standards that describes the substantive or procedural action or inaction associated with a Reliability Standard or the standards process. The appellant describes in the complaint the actual or potential adverse impact to the appellant. Assisted by any necessary NPCC Standards Staff and Committee resources, the NPCC Manager of Reliability Standards shall prepare a written response addressed to the appellant as soon as practical, but not more than forty-five (45) calendar days after receipt of the complaint. If the appellant accepts the response as a satisfactory resolution of the issue, both the complaint and response will be made a part of the public record associated with the standard and posted with the standard.

LEVEL 2 APPEAL

If after the Level 1 Appeal the appellant remains unsatisfied with the resolution, as indicated by the appellant in writing to the NPCC Manager of Reliability Standards, the NPCC Board of Directors shall appoint a five member panel to serve as a Level 2 Appeals Panel.

In all cases, Level 2 Appeals Panel members shall have no direct affiliation with the participants in the appeal.

The NPCC Manager of Reliability Standards shall post the complaint and other relevant materials and provide at least a thirty (30) calendar day notice of the meeting of the Level 2 Appeals Panel.

In addition to the appellant, any person that is directly and materially affected by the substantive or procedural action or inaction referenced in the complaint shall be heard by the panel. The panel shall not consider any expansion of the scope of the appeal that was not presented in the Level 1 Appeal. The panel may in its decision find for the appellant and remand the issue to the RSC with a statement of the issues and facts in regard to which unfair and/or inequitable action was taken, or which fair and/or equitable action was not taken. The panel may find for or against the appellant with a specific statement of the facts that demonstrate fair and equitable treatment of the appellant and the appellant's objections. The panel may not, however, revise, approve, disapprove, or adopt a Reliability Standard. The actions of the Level 2 Appeals Panel shall be publicly posted.

In addition to the foregoing, a procedural objection that has not been resolved may be submitted to the NPCC Board of Directors for consideration at the time the Board decides whether to adopt a particular Reliability Standard. The objection must be in writing, signed by an officer of the objecting entity, and contain a concise statement of the relief requested and a clear demonstration of the facts that justify that relief. The objection must be filed no later than thirty (30) calendar days after the announcement of the vote on the standard in question.

APPENDIX A: RSAR COMPLETION GUIDELINES

The Requester shall complete an RSAR form in accordance with the guidance provided below.

The RSAR, at a minimum, shall contain information in the required fields in order to be qualified for consideration. The NPCC Manager of Reliability Standards will assist the Requester to ensure all required information is submitted on the RSAR.

Information in a Regional Standard Authorization Request (RSAR)

The tables below identify information to be submitted in a Regional Standard Authorization Request to the NPCC Manager of Reliability Standards, at npccstandard@npcc.org. The NPCC Manager of Reliability Standards shall be responsible for implementing and maintaining this form as needed to support the information requirements of the standards process.

Regional Standard Authorization Request Form

Title of Proposed Standard:	***[Required Field]***
Request Date:	***[Required Field]***

RSAR Requester Information

Name:	***[Required Field]***	**RSAR Type (Check box for one of these selections.)**	
Company:	***[Required Field]***	☐	New Standard
Telephone:	***[Required Field]***	☐	Revision to Existing Standard
Fax:		☐	Withdrawal of Existing Standard
Email:	***[Required Field]***	☐	Urgent Action

Purpose: (Describe the purpose of the proposed standard – what the standard will achieve in support of reliability.)

[Required Field]

Industry Need: (Provide a detailed statement justifying the need for the proposed standard, along with a technical justification and any supporting documentation.)

[Required Field -- must include technical justification (relevant studies, documentation, etc.) for a new standard or revision to an existing standard.]

Brief Description: (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

[Required Field]

Reliability Functions *[Required Field]*

The Standard will Apply to the Following Functions (Check all applicable boxes.)		
☐	Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
☐	Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☐	Planning Authority	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
☐	Transmission Service Provider	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
☐	Transmission Owner	The entity that owns and maintains transmission facilities.
☐	Transmission Operator	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
☐	Transmission Planner	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
☐	Resource Planner	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
☐	Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
☐	Generator Owner	Entity that owns and maintains generating units.

☐	Purchasing-Selling Entity	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
☐	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer.
☐	Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check all boxes that apply.)*	
☐	1. Interconnected Bulk Electric System 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 Electric System 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 Electric System 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 Electric System 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 Electric System.
☐	6. Personnel responsible for planning and operating interconnected Bulk Electric System shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected Bulk Electric System shall be assessed, monitored, and maintained on a wide-area basis.
Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*	
Recognizing that reliability is an Common Attribute of a robust North American economy:	
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

Detailed Description: (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.) ***[Required Field – Provide: 1) Necessary information to assist the drafting team (which is to include relevant study results and documentation), to the extent feasible, to allow them to draft the standard, 2) Any existing known cross references to NPCC or NERC documents and 3) Technical background for the RSAR to properly address the need for the standard.]***

Related Standards *[Required Field, to extent known]*

Standard No.	Explanation

Related SARs or RSARs *[Required Field, to extent known]*

SAR ID	Explanation

APPENDIX B: SELECTION OF DRAFTING TEAM MEMBERS

A regional standard drafting team shall be comprised of Subject Matter Experts (SMEs) from NPCC Task Forces and Working Groups as determined by the RCC, and from industry. The guidelines provided herein primarily address overall team requirements and more specifically those of a SME.

Formal membership on a drafting team should be reserved only for those individuals who intend to work consistently, diligently, and professionally on what is required to be done for a regional standard. Drafting team members are expected to contribute meaningfully to the ongoing development of the standard.

Drafting Team members must be:

- Committed to participating in scheduled drafting team meetings, teleconferences, as well as industry outreach (e.g., workshops and webinars)
- Willing to lead teams / sub-teams, as necessary
- Champions for standard development and promoters of the approval of the standard
- Open to consider the comments of others and provide constructive feedback

Commented [HS15]: I think you should remove this. They should neither be champions or detractors. They should be working in the best interests of reliability.

Subject Matter Experts should possess the necessary expertise and knowledge regarding the topic of the standard. The SMEs should represent a cross section of the registered entities applicable to the standard under development as well as geographical areas within the NPCC footprint.

Industry stakeholders may nominate themselves for consideration by the NPCC Regional Standards Committee (RSC) for the specific drafting team vacancies by completing the following drafting team Self Nomination form and submitting it to NPCC Manager of Reliability Standards, at npccstandard@npcc.org.

Nomination Form for NPCC [Name of drafting team] Drafting Team

Please return this form as soon as possible. If you have any questions, please contact the NPCC Standards Staff at npccstandard@npcc.org.

By submitting the following information you are indicating your willingness and agreement to actively participate in the drafting team meetings if appointed to the drafting team by the NPCC Regional Standards Committee (RSC). This means that if you are appointed to the DT you are expected to attend all (or at least the vast majority) of the face-to-face DT meetings as well as participate in all the DT meetings held via conference calls. Failure to do so shall result in your removal from the DT.

Name:	
Organization:	
Address:	
Telephone:	

E-mail:	

Please briefly describe your experience and qualifications to serve on the requested drafting team.

If you are currently a member of any NERC or Regional drafting teams, please list each team here.

☐ Not currently on any active SAR or standard drafting team.

☐ Currently a member of the following SAR or standard drafting team(s):

If you previously worked on any drafting team please identify the team(s).

☐ No prior NERC or Regional SAR or standard drafting team experience.

☐ Prior experience on the following team(s):

Select each NERC Region that you represent:	Select each Industry Segment that you represent:
☐ ERCOT ☐ FRCC ☐ MRO ☐ NPCC ☐ RFC ☐ SERC ☐ SPP ☐ WECC ☐ NA – Not Applicable	☐ 1 — Transmission Owners ☐ 2 — RTOs, ISOs ☐ 3 — Load-serving Entities ☐ 4 — Transmission-dependent Utilities ☐ 5 — Electric Generators ☐ 6 — Electricity Brokers, Aggregators, and Marketers ☐ 7 — Large Electricity End Users ☐ 8 — Small Electricity End Users ☐ 9 — Federal, State, and Provincial Regulatory or other Government Entities ☐ 10 — Regional Reliability Organizations and Regional Entities ☐ NA – Not Applicable

Select each Function[20] in which you have current or prior expertise:

☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

Commented [HS16]: This part of the form seems wrong. They should be from entities with interests in the NPCC region but have knowledge of the ERO framework as a whole.

What if we decide we need a storage standard for example.

Commented [HS17]: We may want to add distributed Energy Resources as one of the check boxes

[20] These functions are defined in the NERC Functional Model, which is downloadable from the NERC website.

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	

APPENDIX C: MAINTENANCE OF REGIONAL STANDARDS AND PROCESS

NPCC regional standards and the Regional Standard Processes Manual are living documents that will be updated periodically to remain current and viable (e.g., respond to changing conditions, as well as to incorporate lessons learned and process improvements).

MAINTENANCE OF REGIONAL STANDARDS

NPCC regional standards will be posted for open process review by the RSC for possible revision at least once every five (5) years[21] after the first regulatory approval and follow the same process as in the case of a new standard. If no changes are warranted, the Regional Standards Committee (RSC) shall recommend to the NPCC Board that the standard be reaffirmed. If the review indicates a need to revise or retire a regional standard, a Regional Standard Authorization Request shall be prepared by the RSC and submitted in accordance with the NPCC regional standards process. The existing, approved standard subject to revision will remain in effect until such time as the revised version has received FERC or applicable Provincial Governmental Authorities approvals, as appropriate, at which time it will be retired in accordance with any applicable implementation plan associated with the newly approved regional standard.

MAINTENANCE OF THE REGIONAL STANDARDS PROCESS

This NPCC Regional Standards Process will be reviewed for possible revision at least once every five (5) years, or more frequently if needed, and subject to the same procedure as applies to the development of a Regional Standard. All such revisions shall be subject to approval by the NPCC Board of Directors, NERC Board of Trustees, FERC, and may be subject to approval, if required, by Applicable Governmental Authorities in Canada.

[21] More frequent reviews of NPCC regional standards may be required to promptly evaluate new or revised NERC reliability standards to ensure NPCC regional standards remain consistent and more stringent than continent-wide reliability standards.

APPENDIX D: NPCC CLARIFICATION REQUEST



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

Note: A valid clarification request is one that requests additional clarity about one or more requirements in approved NPCC regional standards, but does not request approval as to how to comply with one or more requirements.

When completed, email this form to:
npccstandard@npcc.org
For questions about this form or for assistance in completing the form, call Lee Pedowicz at 212-840-1070.

Commented [RS18]: Quintin Lee's Comment: Does Lee need to be replaced here?

Request for an Clarification of a Regional Standard	
Date submitted:	
Contact information for person requesting the clarification:	
Name:	
Organization:	
Telephone:	E-mail:
Identify the standard that needs clarification:	
Standard Number (include version number, e.g. PRC-006-NPCC-1):	
Standard Title:	
Identify specifically what requirement needs clarification:	
Requirement Number and Text of Requirement:	
Identify the nature of clarification that is requested: (Check as many as applicable)	
☐ Clarify the required performance ☐ Clarify the conditions under which the performance is required ☐ Clarify which functional entity is responsible for performing an action in a requirement ☐ Clarify the reliability outcome the requirement is intended to produce Please explain the clarification needed:	
Identify the material impact associated with this clarification:	

Identify the material impact to your organization or others, if known, caused by the lack of clarity or an incorrect clarification of this standard.

Recent FERC Activity

Kal Ayoub, Deputy Director, Division of Reliability Standards and Security
FERC, Office of Electric Reliability
November 6, 2018

This is a staff briefing and does not necessarily represent the views of the Commission or any individual Commissioner

Andy Dodge, OER Director, 10/25/18

- Andy joined the Commission in October 2016, where he served as an Electrical Engineer in the Office of Energy Infrastructure Security (OEIS).

- Andy has over 30 years of industry and regulatory experience as a proven executive leader and electrical power engineer in all aspects of electric transmission and distribution utilities. Prior to joining the Commission, he served as the Chief Engineer (Director, Engineering Division) for the Maryland Public Service Commission.

- In addition, he served as Vice President for Technical Services, Vice President for Electric System Operations and Planning, Vice President for Transmission Operations and Planning, and Vice President for Distribution Operations and Planning for Baltimore Gas and Electric (BGE).

- Andy earned a bachelor's degree with honors in electrical engineering from the University of Maryland College Park, and a master's degree in electrical engineering from George Washington University. He is also a registered professional engineer in Maryland.

Supply Chain Risk Management Final Rule

- FERC issued a Final Rule, RM17-13, 10/18/18
- Augments currently-effective CIP reliability standards by approving additional supply chain risk management CIP reliability standards:
  - Supply Chain Risk Management (CIP-013-1)
  - Electronic Security Perimeter(s) (CIP-005-6)
  - Configuration Change Management and Vulnerability Assessments (CIP-010-3)
- Directs NERC to include Electronic Access Control and Monitoring Systems (EACMS) associated with high- and medium-impact BES cyber systems in the scope of the standards and to evaluate risks presented by low-impact BES Cyber Systems, and by Physical Access Control Systems (PACS) and Protected Cyber Assets (PCAs).
- Directs NERC to file the BOT-directed study's final report with the Commission upon its completion.
- A revised standard is due 24 months after publication in Federal Register.

FERC-NERC Joint Inquiry into Cold Weather Event

- FERC and NERC launched joint inquiry to assess the extreme cold weather event that occurred in Midwest and South Central U.S. on January 15, 2018.
- Reports of multiple forced generation outages, voltage deviations and near-overloads during peak operations.
- Inquiry will focus on identifying:
  - Causes of event
  - Contributing factors
  - Appropriate recommendations for improving operations under similar conditions
- Inquiry is not an enforcement investigation and will allow FERC and NERC to identify lessons learned as we approach future winter seasons.
- FERC and NERC are working with the Midwest Reliability Organization, ReliabilityFirst, SERC Reliability Corporation and relevant involved companies.

Technical Conference on Winter 2018-2019 Operations & Market Performance in RTOs/ISOs

- Commission held technical conference on 10/18/18.
- Representatives from RTOs/ISOs presented their winter preparedness plans and challenges, and operational system enhancements and market changes to address.
- Topics discussed included:
  - Regions' current level of winter preparedness
  - Market design changes and infrastructure improvements relevant to winter preparedness
  - Biggest challenges last winter and going into this winter, and actions contemplated to mitigate those challenges
  - Efforts to ensure winter preparedness and any changes or evolution in approach following the 2014 Polar Vortex and last winter's Bomb Cyclone

ERO and Regional Entity FY 2019 Budget

- FERC issued Order accepting 2019 Business Plans and Budgets, RR18-9-000.
- Accepts the 2019 business plans and budgets of NERC, the Regional Entities, and the Western Interconnection Regional Advisory Body.
  - Accepts NERC's proposed total funding requirement of $79 million, of which $62 million is allocated to the United States
  - $79 million total funding requirement represents an 8.4% increase over NERC's FY 2018 budget
- Authorizes NERC to issue billing invoices to fund fiscal year 2019 operations.
- Grants NERC's request to allocate certain penalty monies to NERC's assessment stabilization reserve and to use certain existing funds from the assessment stabilization reserve to reduce 2019 assessments.

Recent Approvals via Delegated Letter Orders

- RD18-8-000 NERC petition for approval of proposed Reliability Standard VAR-001-5, Voltage and Reactive Control. (Issued 10/15/18)
- RR18-6-000 NERC's 2017 budget true-up filing showing comparisons between budgeted and actual expenditures, audited financial statements, and administrative cost metrics for itself and the eight Regional Entities for the 2017 fiscal year. (Issued 9/25/18)
- RD18-7-000 NERC petition for approval of proposed Reliability Standard BAL-002-3, Disturbance Control Standard - Contingency Reserve for Recovery from a Balancing Contingency Event. (Issued 9/25/18)
- RR18-7-000 NERC petition for approval of Bylaws Amendments. (Issued 9/25/18)
- RR18-8-000 NERC petition for approval of MRO Bylaws Amendments. (Issued 9/6/18)
- RD18-1-000 NERC/WECC joint petition for approval of the retirement of regional Reliability Standard VAR-002-WECC-2, Automatic Voltage Regulators. (Issued 9/5/18)

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~~

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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.

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

RELIABILITY | ACCOUNTABILITY






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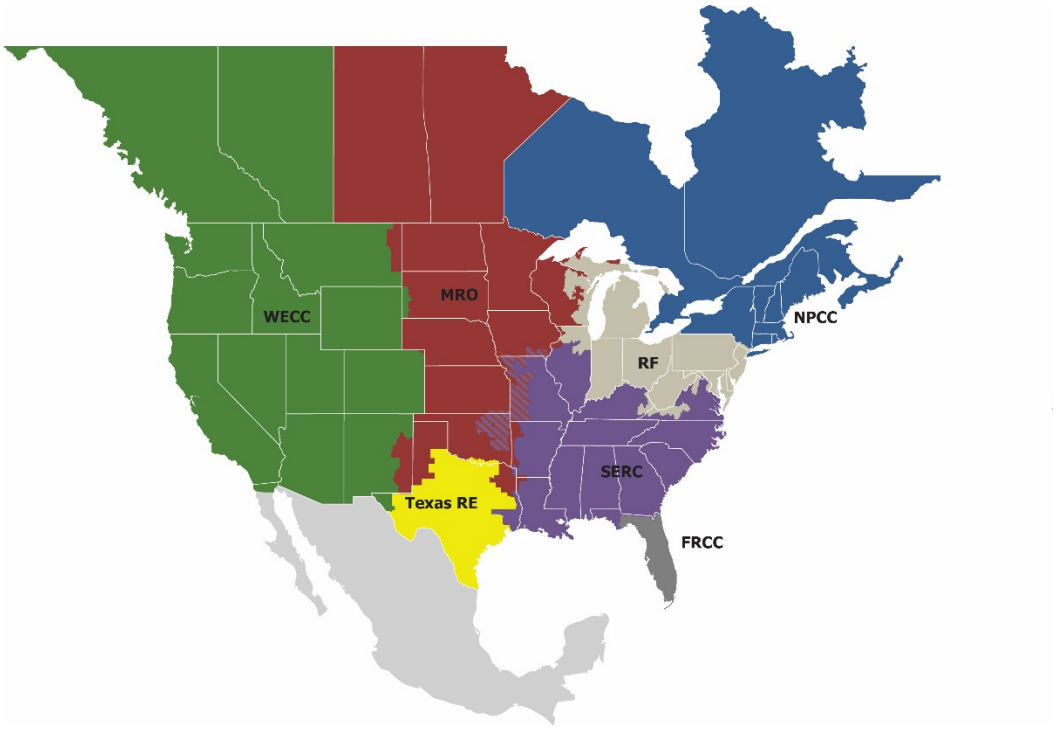
Table of Contents

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.

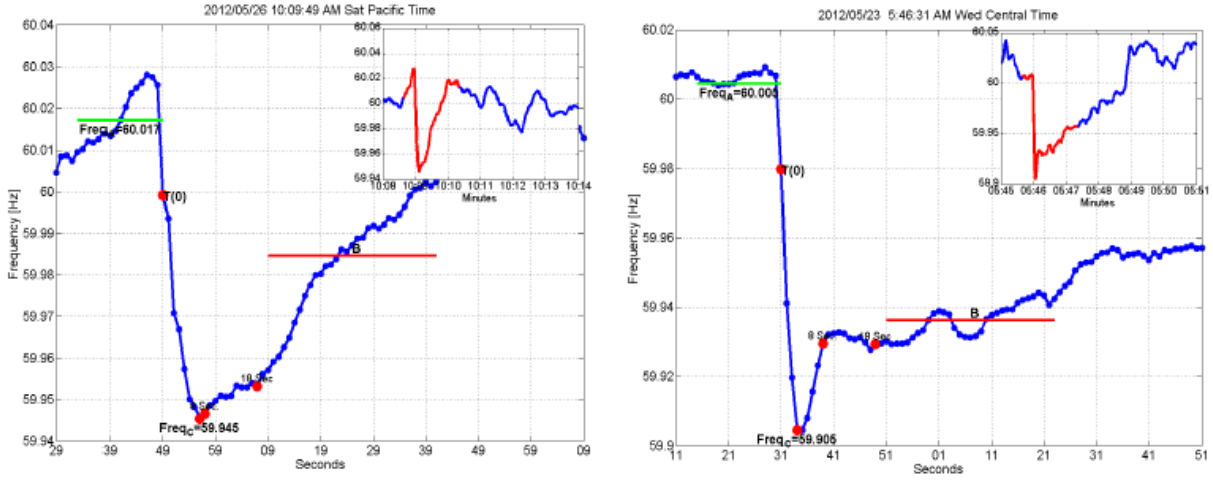


Figure 1.1: Pre-disturbance Frequency

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

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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~~e~~is 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

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Frequency Response Standard Background Document

November, 2012

RELIABILITY | ACCOUNTABILITY






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Table of Contents

Table of Contents 1
Introduction 2
Background 2
Rationale by Requirement 22
Requirement 1 22
Background and Rationale 22
Requirement 2 32
Background and Rationale 32
Requirement 3 34
Requirement 4 34
Background and Rationale 35
How this Standard Meets the FERC Order No. 693 Directives 36
FERC Directive 36
1. Levels of Non-Compliance 36
2. Determine the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other Requirements of the Reliability Standard are met ... 36
3. Define the necessary amount of Frequency Response needed for Reliable Operation for each Balancing Authority with methods of obtaining and measuring that the frequency response is achieved 36
Necessary Amount of Frequency Response 36
Methods of Obtaining Frequency Response 37
Measuring that the Frequency Response is Achieved 37
Going Beyond the Directive 38
Good Practices and Tools 39
Background 39
Identifying and Estimating Frequency Responsive Reserves 39
Using FRS Form 1 Data 40
Tools 40

Introduction

This document provides background on the development, testing and implementation of BAL-003-1 - Frequency Response Standard ("FRS").[1] The intent is to explain the rationale and considerations for the Requirements of this standard and their associated compliance information. The document also provides good practices and tips for Balancing Authorities ("BAs") with regard to Frequency Response.

In Order No. 693, the Federal Energy Regulatory Commission ("FERC" or the "Commission") directed additional changes to BAL-003.[2] This document explains how compliance with those directives are met by BAL-003-1.

The original Standards Authorization Request ("SAR"), finalized on June 30, 2007, assumed there was adequate Frequency Response in all the North American Interconnections. The goal of the SAR was to update the Standard to make the measurement process of frequency response more objective and to provide this objective data to Planners and Operators for improved modeling. The updated models will improve understanding of the trends in Frequency Response to determine if reliability limits are being approached. The Standard would also lay the process groundwork for a transition to a performance-based Standard if reliability limits are approached.

This document will be periodically updated by the FRS Drafting Team ("FRSDT") until the Standard is approved. Once approved, this document will then be maintained and updated by the ERO and the NERC Resources Subcommittee to be used as a reference and training resource.

Background

This section discusses the different components of frequency control and the individual components of Primary Frequency Control also known as Frequency Response.

Frequency Control

Most system operators generally have a good understanding of frequency control and Bias Setting as outlined in the balancing standards and the references to them in the NERC Operating Manual. Frequency control can be divided into four overlapping windows of time as outlined below.

> **Primary Frequency Control (Frequency Response) –** Actions provided by the Interconnection to arrest and stabilize frequency in response to frequency deviations.

[1] Unless otherwise designated herein, all capitalized terms shall have the meaning set forth in the Glossary of Terms Used in NERC Reliability Standards, available here: http://www.nerc.com/files/Glossary_of_Terms.pdf.

[2] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 368-375, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

Primary Control comes from automatic generator governor response (also known as speed regulation), load response (typically from motors), and other devices that provide an immediate response based on local (device-level) control systems.

Secondary Frequency Control – Actions provided by an individual BA or its Reserve Sharing Group to correct the resource – load unbalance that created the original frequency deviation, which will restore both Scheduled Frequency and Primary Frequency Response. Secondary Control comes from either manual or automated dispatch from a centralized control system.

Tertiary Frequency Control – Actions provided by Balancing Authorities on a balanced basis that are coordinated so there is a net zero effect on Area Control Error (ACE). Examples of Tertiary Control include dispatching generation to serve native load; economic dispatch; dispatching generation to affect Interchange; and re-dispatching generation. Tertiary Control actions are intended to replace Secondary Control Response by reconfiguring reserves.

Time Control includes small offsets to scheduled frequency to keep long term average frequency at 60 Hz.

Primary Frequency Control – Frequency Response

Primary Frequency Control, also known generally as **Frequency Response**, is the first stage of overall frequency control and is the response of resources and load to a locally sensed change in frequency in order to arrest that change in frequency. Frequency Response is automatic, not driven by any centralized system, and begins within seconds rather than minutes. Different resources, loads, and systems provide Frequency Response with different response times, based on current system conditions such as total resource/load and their respective mix.

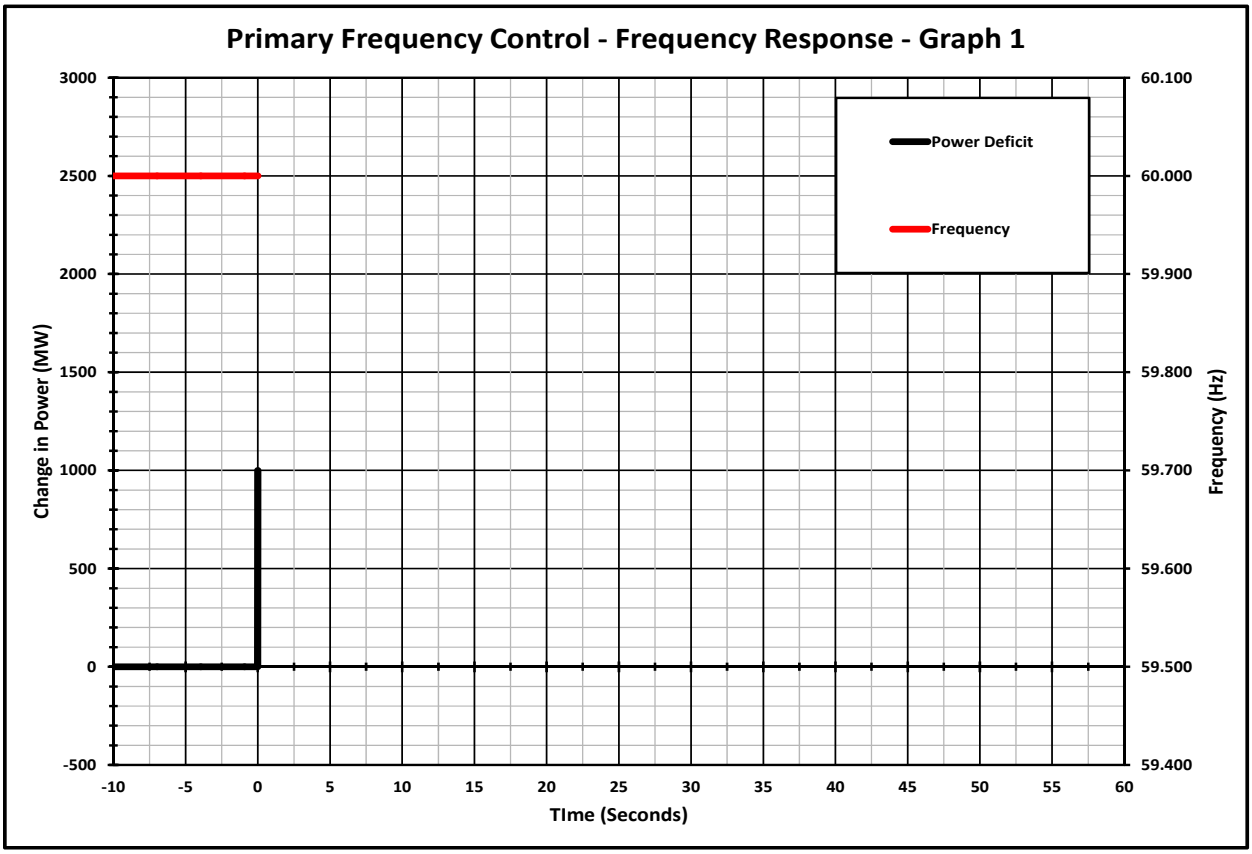
The proposed NERC Glossary of Terms defines **Frequency Response** as:

- (Equipment) The immediate and automatic reaction or response of power from a system or power from elements of the system to a change in locally sensed system frequency.
- (System) The sum of the change in demand, and the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

As noted above, Frequency Response is the characteristic of load and generation within Balancing Authorities and Interconnections. It reacts or responds with changes in power to attempted changes in load-resource balance that result in changes to system frequency. Because the loss of a large generator is much more likely than a sudden loss of an equivalent amount of load, Frequency Response is typically discussed in the context of a loss of a large generator. Included within Frequency Response are many components of that response. Understanding Frequency Response and the FRS requires an understanding of each of these components and how they relate to each other.

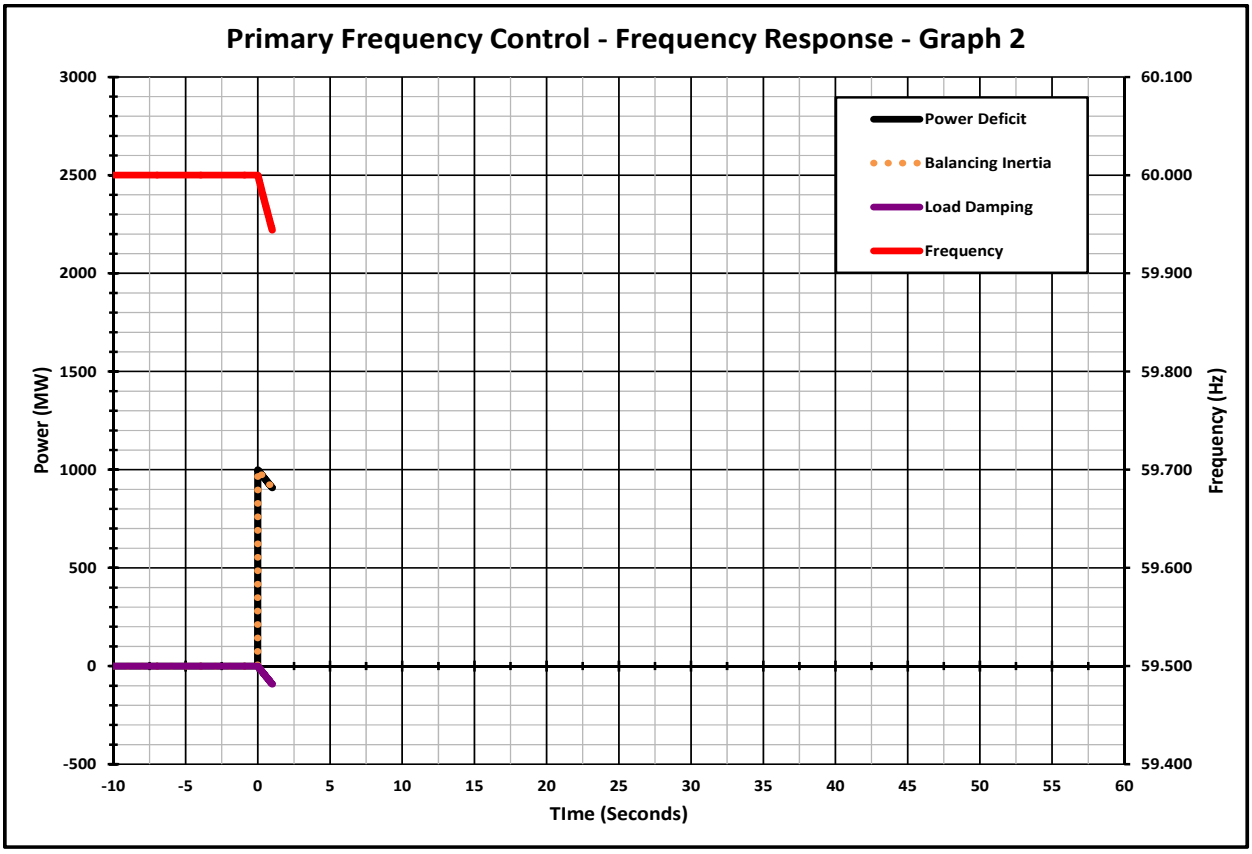
Frequency Response Illustration

The following simple example is presented to illustrate the components of Frequency Response in graphical form. It includes a series of seven graphs that illustrate the various components of Frequency Response and a brief discussion of each describing how these components react to attempted changes in the load-resource balance and resulting changes in system frequency. The illustration is based on an assumed Disturbance event of the sudden loss of 1000 MW of generation. Although a large event is used to illustrate the response components, even small frequently occurring events will result in similar reactions or responses. The magnitude of the event only affects the shape of the curves on the graph; it does not obviate the need for Frequency Response.



The first graph, Primary Frequency Control – Frequency Response – Graph 1, presents a sudden loss of generation of 1000 MW. The components are presented relative to time as shown on the horizontal Time axis in seconds. This simplified example assumes a Disturbance event of the sudden loss of generation resulting from a breaker trip that instantaneously removes 1000 MW of generation from the interconnection. This sudden loss is illustrated by the power deficit line shown in black using the MW scale on the left. Interconnection frequency is illustrated by the frequency line shown in red using the Hertz scale on the right. Since the Scheduled Frequency is normally 60 Hz, it is assumed that this is the frequency when the Disturbance event occurs.

Even though the generation has tripped and power injected by the generator has been removed from the interconnection, the loads continue to use the same amount of power. The "Law of Conservation of Energy"[3] requires that the 1000 MW must be supplied to the interconnection if energy balance is to be "conserved." This additional 1000 MW of power is produced by extracting kinetic energy that was stored in the rotating mass of all of the synchronized generators and motors on the interconnection – essentially using this equipment as a giant flywheel. The extracted energy supplies the "balancing inertia"[4] power required to maintain the power and energy balance on the interconnection. This balancing inertia power is produced by the generators' spinning inertial mass' resistance to the slowdown in speed of the rotating equipment on the interconnection that both provides the stored kinetic energy and reduces the frequency of the interconnection. This is illustrated in the second graph, Primary Frequency Control – Frequency Response – Graph 2, by the orange dots representing the balancing inertia power that exactly overlay and offset the power deficit.



As the frequency decreases, synchronized motors slow, as does the work they are providing, resulting in a decrease in load called "load damping." This load damping is the reason that the power deficit initially declines. Synchronously operated motors will contribute to load

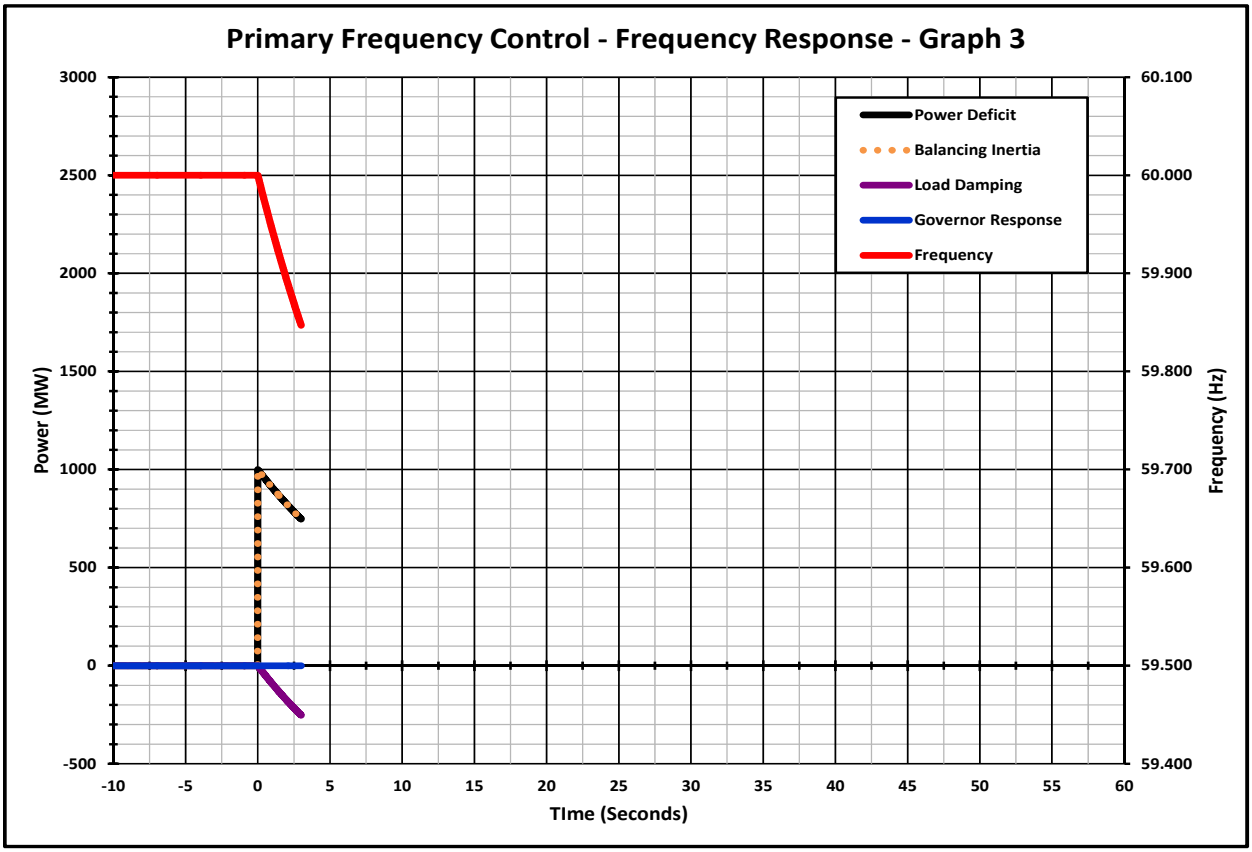
[3] The "Law of Conservation of Energy" is applied here in the form of power. If energy must be conserved, then power which is the first derivative of energy with respect to time, must also be conserved.

[4] The term "balancing Inertia" is coined here from the terms "inertial frequency response" and "balancing energy". Inertial frequency response is a common term used to describe the power supplied for this portion of the frequency response and balancing energy is a term used to describe the market energy supposedly purchased to restore energy balance.

damping. Variable speed drives that are decoupled from the interconnection frequency do not contribute to load damping. In general, any load that does not change with interconnection frequency including resistive load will not contribute to load damping or Frequency Response.

It is important to note that the power deficit equals exactly the balancing inertia, indicating that there is no power or energy imbalance at any time during this process. What is normally considered as "balancing power or energy" is actually power or energy required to correct the frequency error from scheduled frequency. Any apparent power or energy imbalance is corrected instantaneously by the balancing inertia power and energy extracted from the interconnection. Thus the balancing function is really a frequency control function described as a balancing function because ACE is calculated in MWs instead of Hertz, frequency error.

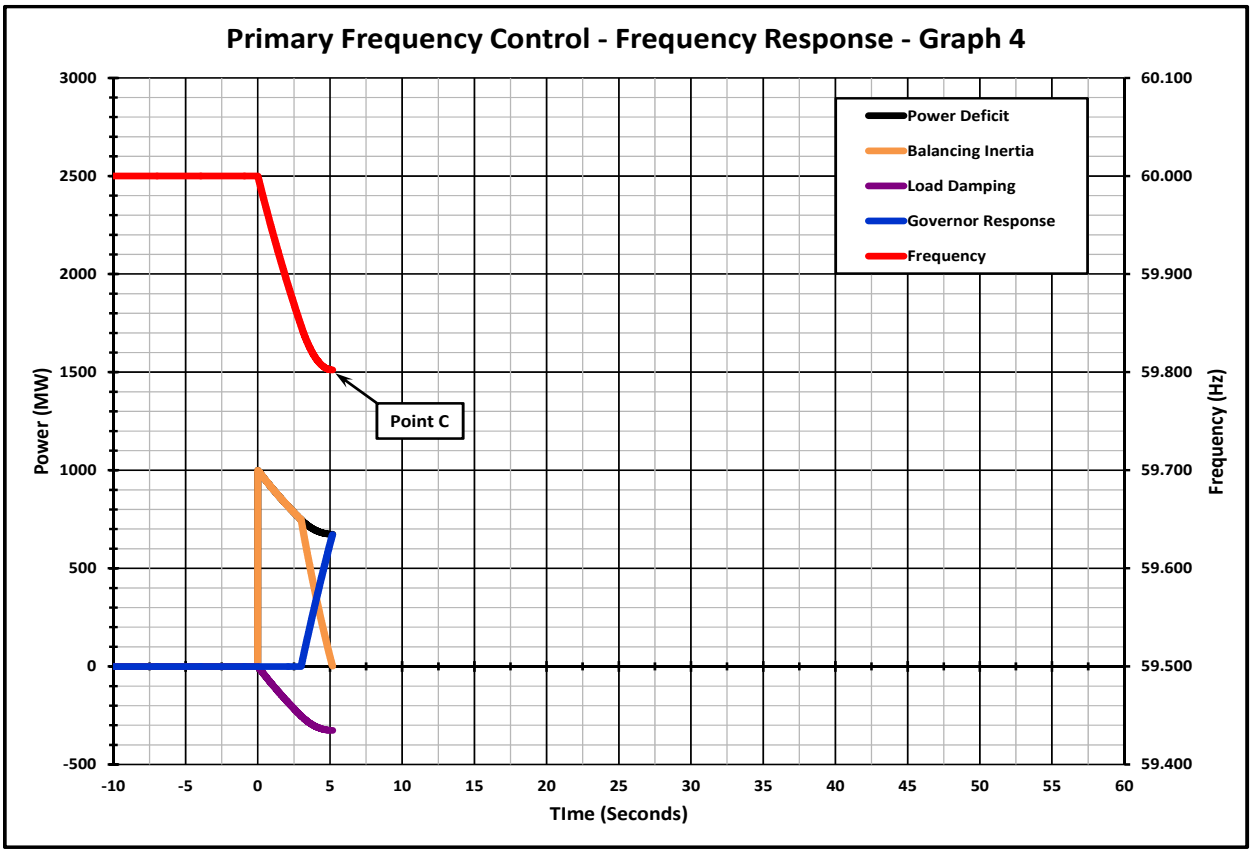
During the initial seconds of the Disturbance event, the governors have yet to respond to the frequency decline. This is illustrated with the Blue line on the third graph, Primary Frequency Control – Frequency Response – Graph 3, showing Governor Response. This time delay results from the time that it takes the controller to adjust the equipment and the time it takes the mass to flow from the source of the energy (main steam control valve for steam turbines, the combustor for gas turbines, or the gate valve for hydro turbines) to the turbine-generator blades where the power is converted to electrical energy.



Note that the frequency continues to decline due to the ongoing extraction by balancing inertia power of energy from the rotating turbine-generators and synchronous motors on the

interconnection. The reduction in load also continues as the effect of load damping continues to reduce the load while frequency declines. During this time delay (before the governor response begins) the balancing inertia limits the rate of change of frequency.

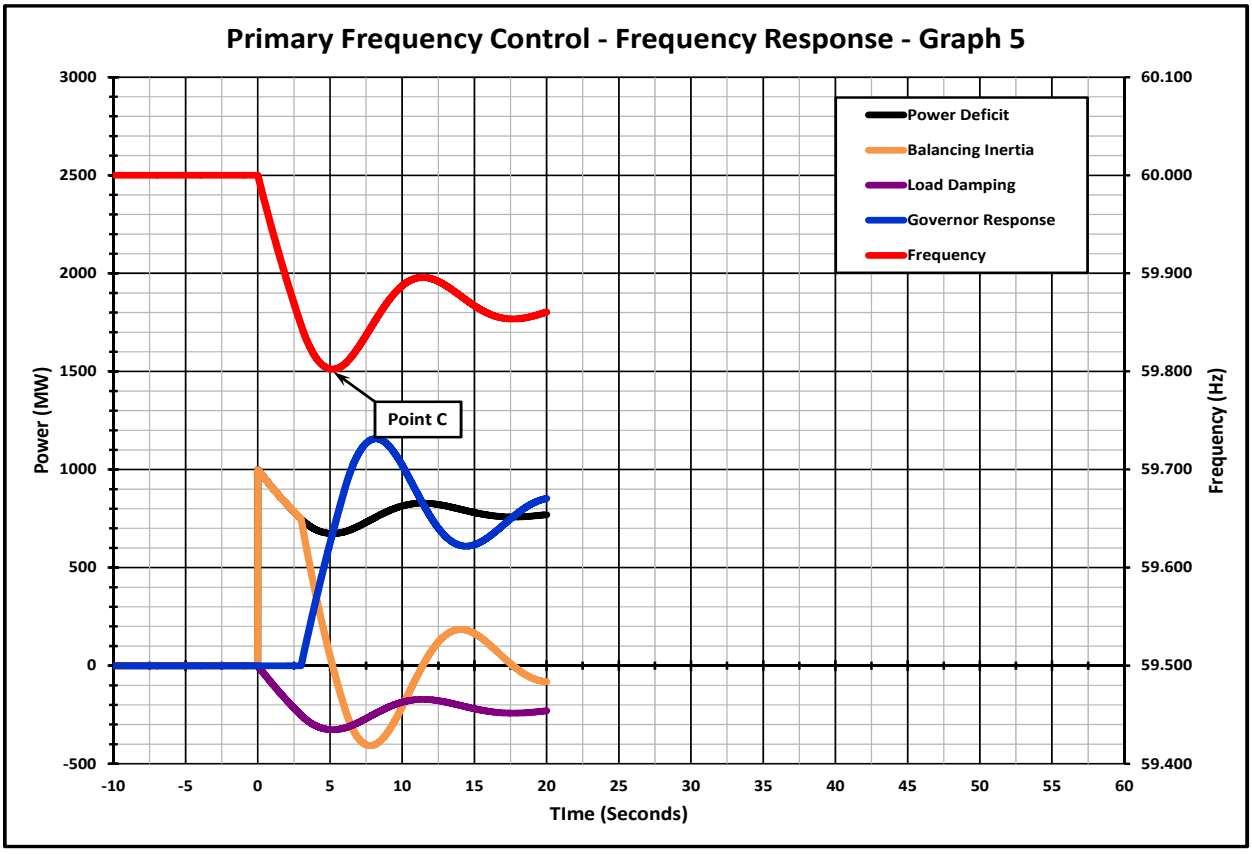
After a short time delay, the governor response begins to increase rapidly in response to the initial rapid decline in frequency, as illustrated on the fourth graph, Primary Frequency Control – Frequency Response – Graph 4. Governor response exactly offsets the power deficit at the point in time that the frequency decline is arrested. At this point in time, the balancing inertia has provided its contribution to reliability and its power contribution is reduced to zero as it is replaced by the governor response. If the time delay associated with the delivery of governor response is reduced, the amount of balancing inertia required to limit the change in frequency by the Disturbance event can also be reduced. This supports the conclusion that balancing inertia is required to manage the time delays associated with the delivery of Frequency Response. Not only is the rapid delivery of Frequency Response important, but the shortening of the time delay associated with its delivery is also important. Therefore, two important components of Frequency Response are 1) how long the time delay is before the initial delivery of response begins; and 2) how much of the response is delivered before the frequency change is arrested.



This point, at which the frequency is first arrested, is defined as "Point C" and Frequency Response calculated at this point is called the "**arrested frequency response**." The arrested

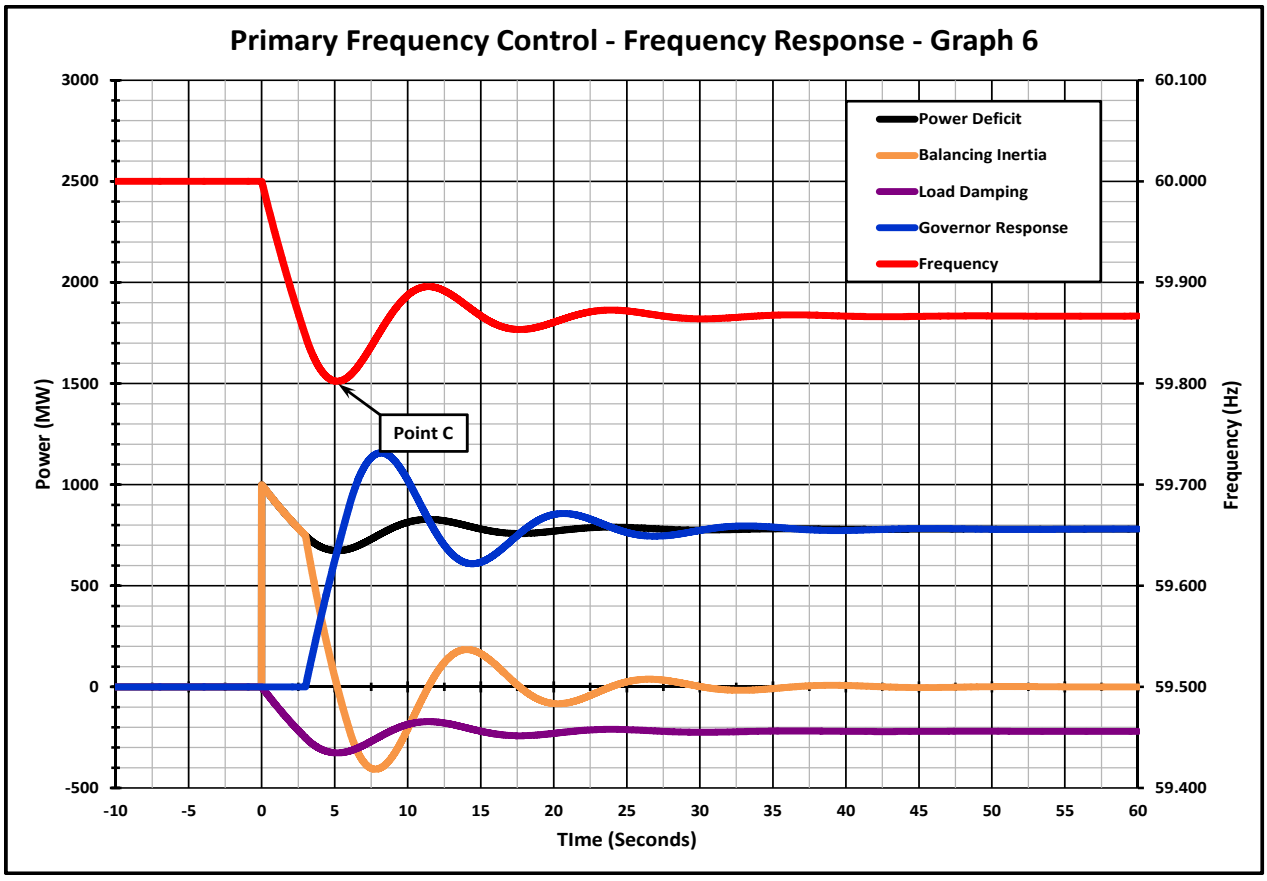
frequency is normally the minimum (maximum for load loss events) frequency that will be experienced during a Disturbance event. From a reliability perspective, this minimum frequency is the frequency that is of concern. Adequate reliability requires that frequency at the time frequency is arrested remain above the under-frequency relay settings so as not to trip these relays and the firm load interrupted by them. Frequency Response delivered after frequency is arrested at this minimum level provides less reliability value than Frequency Response delivered before Point C, but greater value than Secondary Frequency Control power and energy which is delivered minutes later.

Once the frequency decline is arrested, the governors continue to respond because of the time delay associated with their Governor Response. This results in the frequency partially recovering from the minimum arrested value and results in an oscillating transient that follows the minimum frequency (arrested frequency) until power flows and frequency settle during the transient period that ends roughly 20 seconds after the Disturbance event. This post-disturbance transient period is included on the fifth illustrative graph, Primary Frequency Control – Frequency Response – Graph 5.

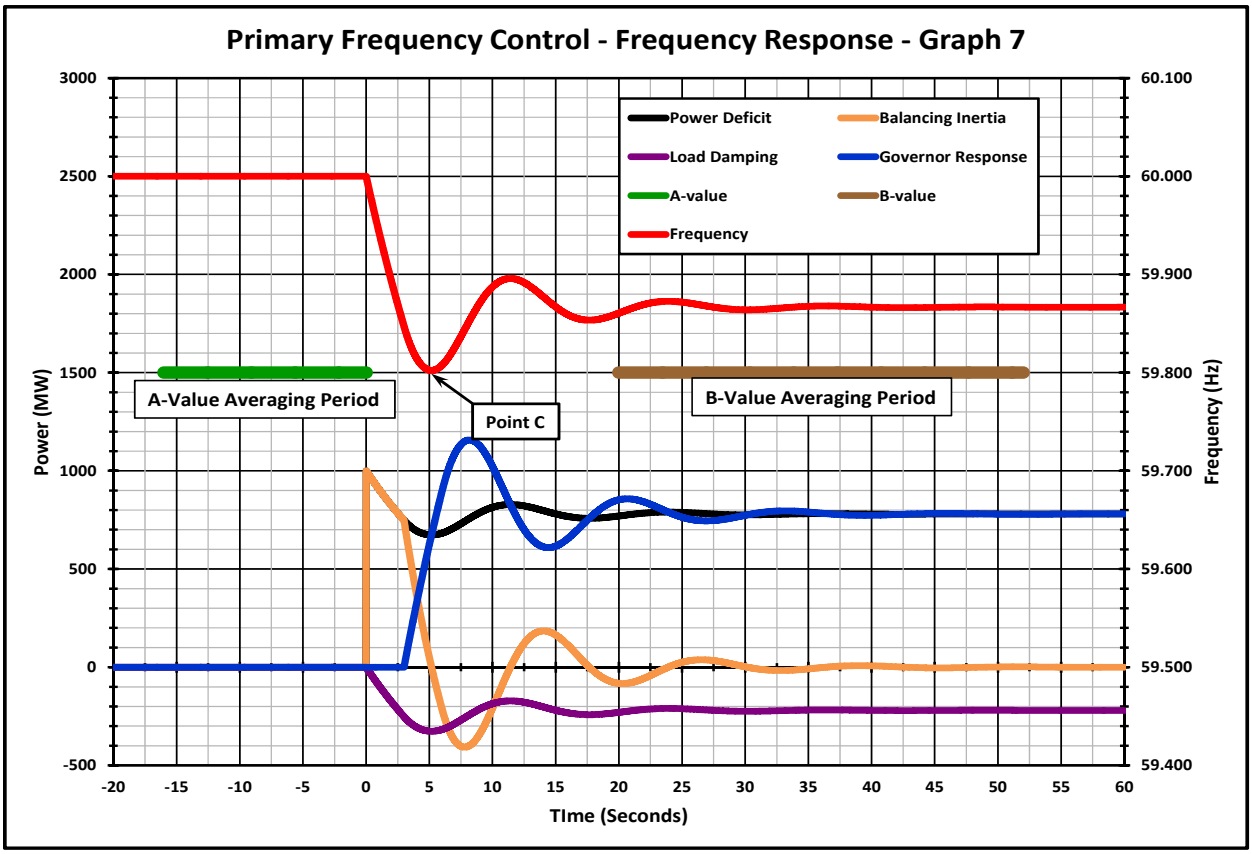


The total Disturbance event illustration is presented on the sixth graph, Primary Frequency Control – Frequency Response – Graph 6. Frequency and power contributions stabilize at the end of the transient period. Frequency Response calculated from data measured during this

settled period is called the “Settled Frequency Response.” The Settled Frequency Response is the best measure to use as an estimator for the “Frequency Bias Setting” discussed later.



The final Disturbance event illustration is presented on the seventh graph, Primary Frequency Control – Frequency Response – Graph 7. This graph shows the averaging periods used to estimate the pre-disturbance A-Value averaging period and the post-disturbance B-Value averaging period used to calculate the settled frequency response. A discussion of the measurement of Frequency Response immediately follows these graphs. That discussion includes consideration of the factors that affect the methods chosen to measure Frequency Response for implementation in a reliability standard.



Frequency Response Measurement (FRM)

The classic Frequency Response points A, C, and B, shown below in Fig. 1 Frequency Response Characteristic, are used for measurement as found in the Frequency Response Characteristic Survey Training Document within the NERC operating manual, found at http://www.nerc.com/files/opman_7-1-11.pdf. This traditional Frequency Response Measure has recently been more specifically termed "**settled frequency response**." This term has been used because it provides the best Frequency Response Measure to estimate the Frequency Bias Setting in Tie-line Bias Control based Automatic Generation Control Systems. However, the industry has recognized that there is considerable variability in measurement resulting from the selection of Point A and Point B in the traditional measure making the traditional measurement method unsuitable as the basis for an enforceable reliability standard in a real world setting of multiple Balancing Authority interconnections.

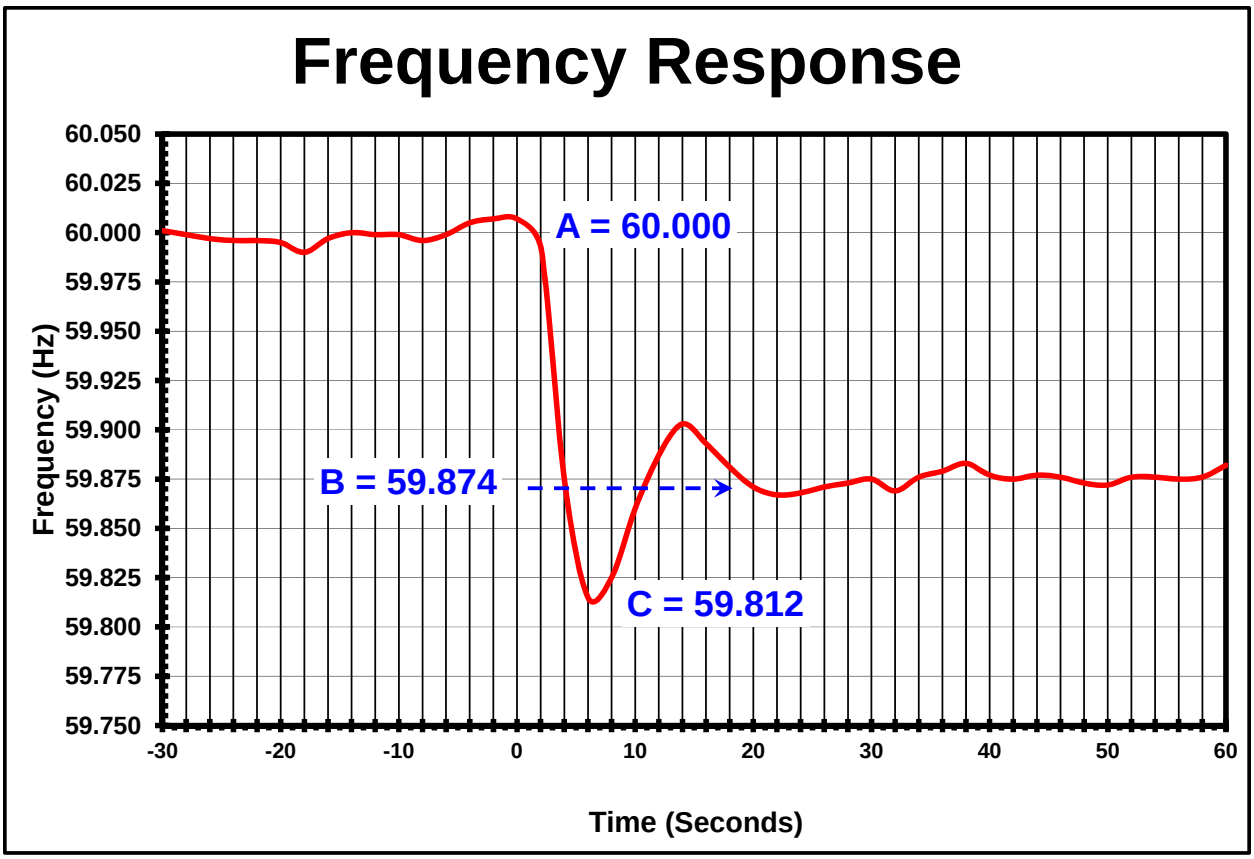


Figure 1. Frequency Response Characteristic

By contrast, measuring an Interconnection's settled frequency response is straightforward and fairly accurate. All that's needed to make the calculation is to know the size of a given contingency (MW), divide this value by the change in frequency and multiply the results by 10 since frequency response is expressed in MW/0.1Hz.

Measuring a BA's frequency response is more challenging. Prior to BAL-003-1, NERC's *Frequency Response Characteristic Survey Training Document* provided guidance to calculate Frequency Response. In short, it told the reader to identify the BA's interchange values "immediately before" and "immediately after" the Disturbance event and use the difference to calculate the MWs the BA deployed for the event. There are two challenges with this approach:

- Two people looking at the same data would come up with different values when assessing which exact points were immediately before and after the event.
- In practice, the actual response provided by the BA can change significantly in the window of time between point B and when secondary and tertiary control can assist in recovery.

Therefore, the measurement of settled frequency response has been standardized in a number of ways to limit the variability in measurement resulting from the poorly specified selection of Point A and Point B. It should be noted that t-0 has been defined as the first scan value that

shows a deviation in frequency of some significance, usually approaching about 10 mHz. The goal is such that the first scan prior to t-0 was unaffected by the deviation and appropriate for one of the averaging points.

- The A-value averaging period of approximately the previous 16 seconds prior to t-0 was selected to allow for an averaging of at least 2 scans for entities utilizing 6 second scan rates. (All time average period references in this document are for 2 second scan rates unless noted otherwise.)
- The B-value averaging period of approximately (t+20 to t+52 seconds) was selected to attempt to obtain the average of the data after primary frequency response was deployed and the transient completed(settled), but before significance influence of secondary control. Multiple periods were considered for averaging the B-value:
    - 12 to 24 sec
    - 18 to 30 sec
    - 20 to 40 sec
    - 18 to 52 sec
    - 20 to 52 sec

  It is necessary for all BAs from an interconnection to use the same averaging periods to provide consistent results. In addition, the SDT decided that until more experience is gained, it is also desirable for all interconnections to use the same averaging periods to allow comparison between interconnections.

The methods presented in this document only address the values required to calculate the frequency response associated with the frequency change between the initial frequency, A-Value, and the settling frequency, B-Value. No reasonable or consistent calculations can be made relating to the arresting frequency, C-Value, using Energy Management System (EMS) scan rate data as long as 6-seconds or tie-line flow values associated with the minimum value of the frequency response characteristic (C-value) as measured at the BA level.

Both the calculation of the frequency at Point A and the frequency at Point B began with the assumption that a 6-second scan rate was the source of the data. Once the averaging periods for a 6-second scan rate were selected, the averaging periods for the other scan rates were selected to provide as much consistency as possible between BAs with different scan rates.

The Frequency at Point A was initially defined as the average of the two scans immediately prior to the frequency event. All other averaging periods were selected to be as consistent as possible with this 12 second average scan from the 6-second scan rate method. In addition, the "**actual net interchange immediately before Disturbance**" is defined as the average of the same scans as used for the Point A frequency average.

The Frequency at Point B was then selected to be an average as long as the average of 6-second scan data as possible that would not begin until most of the hydro governor response had been delivered and would end before significant Automatic Generation Control (AGC) recovery response had been initiated as indicated by a consistent frequency restoration slope. The "**actual net interchange immediately after Disturbance**" is defined as the average of the same scans as used for the Point B frequency average.

B Averaging Period Selection:

Experience from the Electric Reliability Council of Texas ("ERCOT") and the field trail on other interconnections indicated that the 12 to 24 second and 18 to 30 second averaging periods were not suitable because they did not provide the consistency in results that the other averaging periods provided, and that the remaining measuring periods do not provide significantly different results from each other. The team believed that this was observed because the transients were not complete in all of the samples using these averaging periods.

The 18 to 52 second and 20 to 52 second averaging periods were compared to each other, with the 20 to 52 second period providing more consistent values, believed to result from the incomplete transient in some of the 18 to 52 second samples.

This left a choice between the 20 to 40 second and the 20 to 52 second averaging periods. The team recognized that there would be more AGC response in the 20 to 52 second period, but the team also recognized that the 20 to 52 second period would provide a better measure of squelched response from outer loop control action. The 20 to 52 second period was selected because it would indicate squelched response from outer-loop control and provide incentive to reduce response withdrawal. The final selections for the data averaging periods used in FRS Form 1 are shown in the table below.

Definitions of Frequency Values for Frequency Response Calculation

Scan Rate	T 0 Scan	A Value (average)	B Value (average)
6-Seconds	Identify first significant change in frequency as the T 0 scan	Average of T-1 through T-2 scans	Average of T+4 through T+8 scans
5-Seconds		Average of T-1 through T-2 scans	Average of T+5 through T+10 scans
4-Seconds		Average of T-1 through T-3 scans	Average of T+6 through T+12 scans
3-Seconds		Average of T-1 through T-5 scans	Average of T+7 through T+17 scans
2-Seconds		Average of T-1 through T-8 scans	Average of T+10 through T+26 scans

Consistent measurement of Primary Frequency Response is achievable for a selected number of events and can produce representative frequency response values, provided an appropriate sample size is used in the analysis. Available research investigating the minimum sample size to provide consistent measurements of Frequency Response has shown that a minimum sample size of 20 events should be adequate.

Measurement of Primary Frequency Response on an individual resource or load basis requires analysis of energy amounts that are often small and difficult to measure using current methods. In addition, the number of an interconnection's resources and loads providing their response could be problematic when compiling results for multiple events.

Measurement of Primary Frequency Response on an interconnection (System) basis is straight forward provided that an accurate frequency metering source is available and the magnitude of the resource/load imbalance is known in MWs.

Measurement on a Balancing Authority basis can be a challenge, since the determination of change in MWs is determined by the change in the individual BA's metered tie lines. Summation of tie lines is accomplished by summing the results of values obtained by the digital scanning of meters at intervals up to six seconds, resulting in a non-coincidental summing of values. Until the technology to GPS time stamp tie line values at the meter and the summing of those values for coincidental times is in use throughout the industry, it is necessary to use averaging of values described above to obtain consistent results.

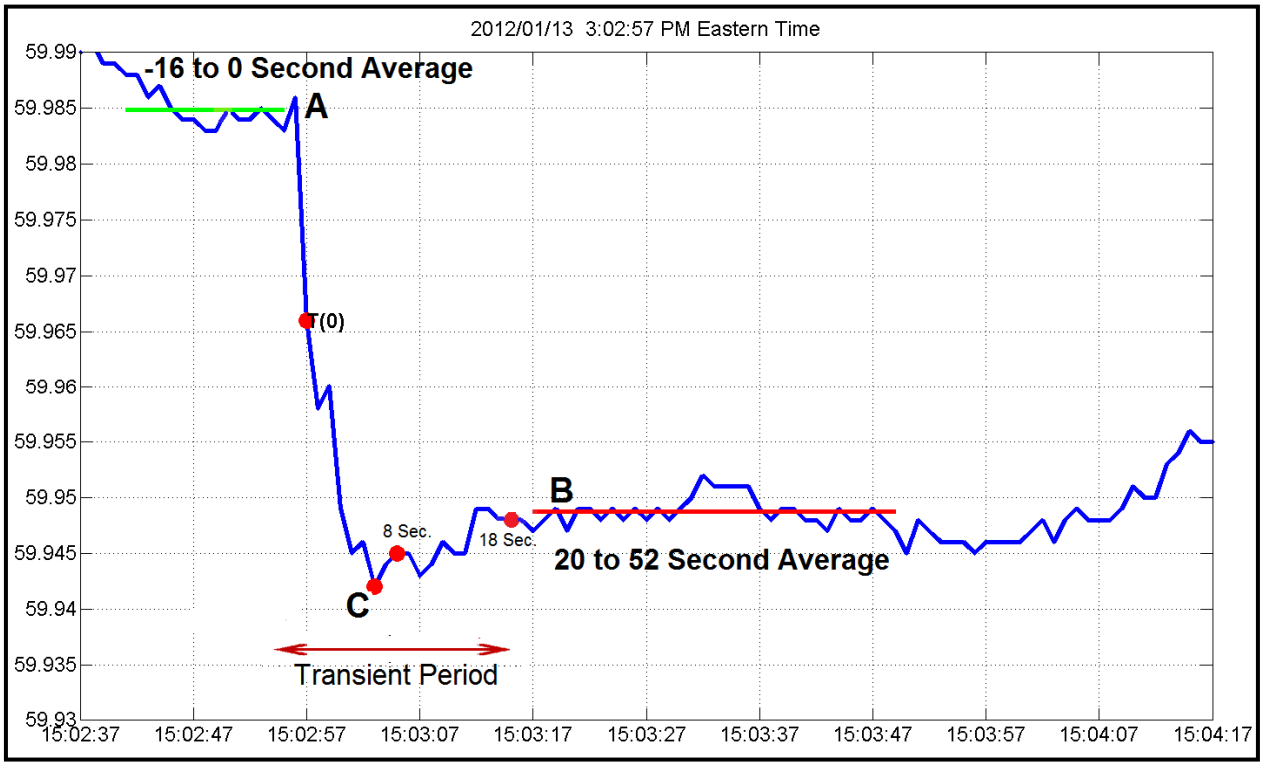


Figure 2. Frequency Response Measurement

The standardized measure is shown graphically in Fig. 2 Frequency Response Measurement with the averaging periods shown by the solid green and red lines on the graph. Since FERC directed a performance obligation for BAL-003-1, it is important to be more objective in the measurement process. The standardized calculation is available on FRS Form 2 for EMS scan rates of 2, 3, 4, 5, and 6 seconds at http://www.nerc.com/filez/standards/Frequency_Response.html.

Arrested Frequency Response

There is another measure of Frequency Response that is of interest when developing a Frequency Response estimate that not only will be used for estimating the Frequency Bias Setting, but will also be used to assure reliability by operating in a manner that will bound interconnection frequency and prevent the operation of Under-frequency Relays. This Frequency Response Measure has recently been named "**arrested frequency response.**" This Frequency Response is significantly affected by the inertial Frequency Response, the governor Frequency Response and the time delays associated with the delivery of governor Frequency

Response. It is calculated by using the change in frequency between the initial frequency, A, and the maximum frequency change during the event, C, instead of using the change between A and B. Arrested Frequency Response is the correct response for determining the minimum Frequency Response related to under-frequency relay operation and the support of interconnection reliability. This is because it can be used to provide a direct estimate of the maximum frequency deviation an interconnection will experience for an initial frequency and a given size event in MW. Unfortunately, arrested frequency response cannot currently be measured using the existing EMS-based measurement infrastructure. This limitation exists because the scan rates currently used in industry EMSs are incapable of measuring the net actual interchange at the same instant that the maximum frequency deviation is reached. Fortunately, the ratio of arrested frequency response and settled frequency response tends to be stable on an interconnection. This allows the settled frequency response value to be used as a surrogate for the arrested frequency response and implement a reasonable measure upon which to base a standard. One consequence of using the settled frequency response as a surrogate for the arrested frequency response is the inclusion of a large reliability margin in Interconnection Frequency Response Obligation to allow for the difference between the settled frequency response as measured and the arrested frequency response that indicates reliability.

As measurement infrastructure improves one might expect the Frequency Response Obligation to transition to a measurement based directly on the arrested frequency response while the Frequency Bias Setting will continue to be based on the settled frequency response. However, at this time, the measurement devices and methods in use do not support the necessary level of accuracy to estimate arrested frequency response contribution for an individual Balancing Authority.

Frequency Response Definition and Examples

Limitations of the measurement infrastructure determine the measurement methods recommended in this standard. The measurement limitations provide opportunities to improve the Frequency Response as measured in the standard without contributing to an improvement in Frequency Response that contributes to reliability. These definitions and examples provide a basis for determining which contributions to Frequency Response contribute the most to improved reliability. They also provide the basis for determining on a case by case basis whether the individual contributors to the Frequency Response Measure are also contributing to reliability.

General Frequency Response Characteristics

In the simplest case Frequency Response includes any automatic response to changes in local frequency. If that response works to decrease that change in frequency, it is beneficial to reliability. If that response works to increase that change in frequency, it is detrimental to reliability. However, this definition does not address the relative value of one response as compared to other responses that may be provided in a specific case.

There are numerous characteristics associated with the Frequency Response that affect the reliability value and economic value of the response. These characteristics include:

1. **Inertial** – the response is inertial or approximates inertial response

Inertial response provides power without delay that is proportional to the frequency and the change in frequency. Therefore, power provided by electronic control as synthetic Inertial response must be proportional to the frequency and change in frequency and be provided without a time delay.

2. **Immediate** – no unnecessary intentional time delays or reduction in the rate of response delivery
    a. time delay before the beginning of the response
    Turbines that convert heat or kinetic energy have time delays related to the time delay from the time that the control valves are moved to initiate the change in power and the time that the power is delivered to the generator. These times are usually associated with the time it takes a change in mass flow to travel from the control valve to the first blades of the turbine in the turbine generator.

    b. reduction in the rate of response delivery
    There are natural delays associated with the rate of response delivery that are related to the mass flow travel from the first turbine blades to the last turbine blades. In addition, some turbines have intentional delays designed into the control system to slow the rate of change in the delivery of the kinetic energy or fuel to the turbine to prevent the turbine or other equipment from being damaged, hydro turbines, or to prevent the turbine from tripping due to excessive rate of change, gas turbines.

3. **Proportional** – the amount of the total response is proportional to the frequency error
    a. No Deadband – the response is proportional across the entire frequency range
    b. Deadband – the response is only proportional outside of a defined deadband

4. **Bi-directional** – the response occurs to both increases and decreases in frequency

5. **Continuous** – there are no discontinuities in the delivery of the response (no step changes)

6. **Sustained** – the response is sustained until frequency is returned to schedule

Frequency Response Reliability Value

This section contains a more detailed discussion of the various characteristics of Frequency Response listed in the previous section. It also provides an indication of the relative value of these characteristics with respect to their contribution to reliability. Finally, it includes some examples of the described responses.

Inertial Response is provided from the stored energy in the rotating mass of the turbine-generators and synchronous motors on the interconnection. It limits the rate of change of frequency until sufficient Frequency Response can be supplied to arrest the change in frequency. Its reliability value increases as the time delay associated with the delivery of other Frequency Response on the interconnection increases. If those time delays are minimal, then the value of inertial response is low. If all time delays associated with the Frequency Response could be eliminated, then inertial response would have little value.

The reliability value of Inertial Response is the greatest on small interconnections because the size of the Disturbance events is larger relative to the inertia of the interconnection. Electronic controls have been developed to provide synthetic inertial response from the stored energy in asynchronous generators to supplement the natural inertial response. Some Type III & IV Wind Turbines have this capability. In addition, electronically controlled SCRs have been developed that can store energy in the electrical system and release this stored energy to supply synthetic inertial response when required.

Immediate Response is provided by load damping and because the time delays associated with its delivery are very short (related to the speed of electrical signal in the electrical system); load damping requires very little inertial response to limit arrested frequency effectively. Synthetic immediate response can also be supplied from loads because in many cases, there is no mass flow time delay associated with the load process providing the power and energy reduction. Therefore, loads can provide an immediate response with a higher reliability value than generators with time delays required by the physics of the turbine-generator.

Governor response has time delays associated with its delivery. Governor response provided with shorter time delays has a higher reliability value because those shorter time delays require less inertial response to arrest frequency. Governor response is provided by the turbine-generators on the interconnection. Time delays associated with governor response vary depending on the type of turbine-generator providing the response.

The longest time delays are usually associated with high head hydro turbine-generators that require long times from the governor action until the additional mass flow through the turbine. These units may also have the longest delivery time associated with the full delivery of response because of the timing designed into the governor response.[5]

Intermediate time delays are usually associated with steam turbine-generators. The response begins when the steam control valves are adjusted and the steam mass flows from the valves to the first high pressure turbine blades. The delivery times associated with the full delivery of response may require the steam to flow through high, intermediate and low pressure turbines including reheat flows before full power is delivered. These times are shorter than those of the hydro turbine-generators in general, but not as fast as the times associated with gas turbines.[6]

Gas turbines typically have the shortest time delays, because control is provided by injecting more or less fuel into the turbine combustor and adjusting the air control dampers. These control changes can be initiated rapidly and the mass flow has the shortest path to the turbine

[5] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-6 – 1-9.

[6] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-4 – 1-6.

blades. There may be timing limitations related to the rate of change in output of the gas turbine-generator to maintain flame stability in some cases slowing the rate of change.[7]

Synthetic Governor Response can be supplied by certain loads and storage systems. The immediacy of the response is normally limited only by the electronic controls used to activate the desired response. Synthetic response, when it can be supplied immediately without significant time delay, has a higher reliability value because it requires less inertial response to achieve smaller arrested frequency deviations.

Proportional Response indicates that the response provided is proportional in magnitude to the frequency error. Response deadbands cause a non-proportional response and reduce the value of the response with respect to reliability. Contrary to general consensus, deadbands do not reduce the amount of Frequency Response that must be provided, they only transfer the responsibility for providing that Frequency Response from one source on the interconnection to another. For a given response, the response with the smaller deadband has the greater reliability value. Therefore, deadbands should be set to the smallest value that supports overall reliable operation including the reliable operation of the generator.

Electronic controls have also been developed to provide synthetic governor response. When these controls are applied to certain loads or stored energy systems, they can be programmed to provide synthetic governor response similar to the proportional response of a turbine-generator governor. Governor response in generators is limited to a small percentage of the output of the generating unit, while synthetic governor response could be applied to much larger percentages of loads or storage devices providing such response.

Load damping provides a proportional response.

Continuous Response is response that has no discontinuous (step) changes in the frequency versus response curve. Step changes (Non-continuous Response) in the Governor Response curve can lead to frequency instabilities at frequencies near the changes. The ERCOT Interconnection observed this and has since prohibited the use of governor response characteristics incorporating step responses.

Step responses also occur with the implementation of load interruption using under-frequency or over-frequency relays.

Bi-directional Response is response that occurs in both directions, when the frequency is increasing and when the frequency is decreasing. A uni-directional response is a response that only occurs once when frequency is decreasing or when frequency is increasing.

Inertial response, governor response and load damping are all bi-directional responses. Certain loads are capable of providing proportional bi-directional response while others are only capable of providing non-proportional bi-directional response.

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[7] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-16 – 1-19.

The ERCOT Load Resource program is a uni-directional response program. Loads are only tripped when frequency declines below a given set-point. When frequency is restored above that set-point, the loads must be manually reconnected. As a consequence, the Frequency Response only occurs once with declining frequency and does not oppose the increase in frequency after the initial decline. If there should be a frequency oscillation, the uni-directional response will not contribute to the opposition of a second frequency decline across the set-point during an oscillation event. Once a uni-directional response has occurred, it is unavailable for a second decline before reset.

Step or proportional responses implemented bi-directionally can lead to frequency instability when there is less continuous frequency response than the magnitude of the change in continuous response between the trip and reset frequencies in step, or the proportional response rate of change is greater than the underlying continuous response. A step bi-directional response will have the load reconnected as frequency recovers from the event thus opposing the increase in frequency during recovery, and also resetting the load response for the next frequency decline automatically. Bi-directional response obviously has a greater reliability value than uni-directional response.

Sustained Response is provided at its full value until frequency is restored to its scheduled value. On today's interconnections, few frequency responses are fully sustained until frequency has been restored to its scheduled value. On steam based turbine-generators, the steam pressure may drop after a time as the result of the additional steam flow from governor action. However, in general this has not been a problem because most responses are incomplete at the time that frequency has been initially arrested and the additional response has generally been sufficient to make up for more than the these unpreventable reductions in response. However, the intentional withdrawal of response before frequency has been restored to schedule can cause a decline in frequency beyond that which would be otherwise expected. This intentional withdrawal of response is highly detrimental to reliability. Therefore, it can be concluded in general that sustained response has a higher reliability value than un-sustained response.

On an interconnection, the withdrawal of response due to the loss of steam pressure on the steam units may be offset by the slower response of hydro turbine-generators. In these cases, the reliability of the combined response provides a greater reliability value than the individual response of each type. The steam turbine-generators provide a fast response that may be reduced, while the hydro turbine-generators provide a slower response, contributing less to the arresting response, offsetting any reduction by the steam turbine-generators to assure a sustained response.

Sustained Response must also be considered for any resource that has a limited duration associated with its response. The amount of stored energy available from a resource may limit its ability to sustain response for a duration of time necessary to support reliability.

Frequency Response Cost Factors

In every system of exchange there are two sides; the supply side and the demand side. The supply side provides the services used by the demand side. In the case of Frequency Response,

the supply side includes all providers of Frequency Response and the demand side includes all participants that create the need for Frequency Response.

Frequency Response Costs – Supply Side

There are a number of factors that affect the cost of providing Frequency Response from resources. Since there is a cost associated with those factors, some method of appropriate compensation could be made available to those resources providing Frequency Response. Without compensation, providers of Frequency Response will be put in the position of incurring additional cost that can be avoided only by reducing or eliminating the response they provide. These costs are incurred independently of whether provided for in a formal Regional Transmission Organization/Independent System Operator (RTO/ISO) market or in a traditional BA subject to the FERC pro-forma tariffs.

It is the responsibility of the BA or the RTO/ISO to acquire the necessary amount of Frequency Response to support reliability in the most cost effective manner. This function is performed best when the suppliers are evaluated based on the value of the Frequency Response they provide and compensated appropriately for that Frequency Response. Suppliers provide Frequency Response when they are assured that they will receive fair compensation. Before considering how to perform this evaluation and compensation, the costs associated with providing Frequency Response should be understood and evaluated with respect to the level of reliability they offer.

Some cost factors that have been identified for providing Frequency Response include:

1. **Capacity Opportunity Cost** – the costs, including opportunity costs, associated with reserving capacity to provide Frequency Response. These costs are usually associated with the alternative use of the same capacity to provide energy or other ancillary services. There may also be capacity opportunity costs associated with the loss in average capacity by a load providing Frequency Response.
2. **Fuel Cost** – The cost of fuel used to provide the Frequency Response. The costs for fuel to provide Frequency Response can result in energy costs significantly different from the system marginal energy cost, both higher and lower. This is the case when Frequency Response is provided by resources that are not at the system marginal cost.
3. **Energy Efficiency Penalty Costs** – the costs associated with the loss in efficiency when the resource is operated in a mode that supports the delivery of Frequency Response. This cost is usually in the form of additional fuel use to provide the same amount of energy. An example is the difference between operating a steam turbine in valve control mode with an active governor and sliding pressure mode with valves wide open and no active governor control except for over-speed. This cost is incurred for all of the energy provided by the resource, not just the energy provided for Frequency Response. There may be additional energy costs associated with a load providing Frequency Response from loss in efficiency of their process when load is reduced.
4. **Capacity Efficiency Penalty Costs** – the costs associated with any reduction in capacity resulting from the loss of capacity associated with the loss in energy efficiency. When efficiency is lost, capacity may be lost at the same time because of limitations in the amount of input energy that can be provided to the resource.

5. **Maintenance Costs** – the operation of the resource in a manner necessary to provide Frequency Response may result in increases in the maintenance costs associated with the resource.
6. **Emissions Costs** – the additional costs incurred to manage any additional emissions that result when the resource is providing Frequency Response or stands ready to provide Frequency Response.

A good contract for the acquisition of Frequency Response from a resource will provide appropriate compensation to the resource for all of the costs the resource incurs to provide Frequency Response. It will also provide a method to evaluate the least cost mix of resources necessary to provide the minimum required Frequency Response for maintaining reliability. Finally, it will provide the least complex method of evaluation considering the complexity and efficiency of the acquisition process.

Frequency Response Costs – Demand Side

Not only are there costs associated with acquiring Frequency Response from the supplying resources, there are costs associated with the amount of Frequency Response that must be acquired and influenced by those participants that create the need for Frequency Response. If the costs of acquiring Frequency Response from the supply resources can be assigned to those parties that create the need for Frequency Response, there is the promise that the amount of Frequency Response required to maintain reliability can be minimized. The considerations are the same as those that are driving the development of "real time pricing" and "dynamic pricing". If the costs are passed on to those contributing to the need for Frequency Response, incentives are created to reduce the need for Frequency Response making interconnection operations less expensive and more reliable. The problem is to balance both cost and complexity against reliability on both the supply side and the demand side.

Rationale by Requirement

Requirement 1

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 Balancing Authority that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation.

Background and Rationale

R1 is intended to meet the following primary objectives:

- Determine whether a Balancing Authority (BA) has sufficient Frequency Response for reliable operations.
- Provide the feeder information needed to calculate CPS limits and Frequency Bias Settings.

Primary Objective

With regard to the first objective, FRS Form 1 and the process in Attachment A provide the method for determining the Interconnections' necessary amount of Frequency Response and allocating it to the Balancing Authorities. The field trial for BAL-003-1 is testing an allocation methodology based on the amount of load and generation in the BA. This is to accommodate the wide spectrum of BAs from generation-only all the way to load-only.

Frequency Response Sharing Groups (FRSGs)

This standard proposes an entity called FRSG, which is defined as:

> *A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.*

This standard allows Balancing Authorities to cooperatively form FRSGs as a means to jointly meet the FRS. There is no obligation to form or be a part of FRSGs. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of FERC's Order No. 693 directives.

FRSG performance may be calculated 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 sums each participant's individual event performance.

Frequency Response Obligation and Calculation

The basic Frequency Response Obligation is based on annual load and generation data reported in FERC Form 714 (where applicable, see below for non-jurisdictional entities) for the previous full calendar year. The basic allocation formula used by NERC is:

$$\mathrm{FRO_{BA}} = \mathrm{FRO_{Int}} \times \frac{\mathrm{Annual\ Gen_{BA}} + \mathrm{Annual\ Load_{BA}}}{\mathrm{Annual\ Gen_{Int}} + \mathrm{Annual\ Load_{Int}}}$$

Where:

- Annual $\mathrm{Gen_{BA}}$ is the annual "Net Generation (MWh)", FERC Form 714, line 13, column c of Part II - Schedule 3.
- Annual $\mathrm{Load_{BA}}$ is the annual "Net Energy for Load (MWh)", FERC Form 714, line 13, column e of Part II - Schedule 3.
- Annual $\mathrm{Gen_{Int}}$ is the sum of all Annual $\mathrm{Gen_{BA}}$ values reported in that interconnection.
- Annual $\mathrm{Load_{Int}}$ is the sum of all Annual $\mathrm{Load_{BA}}$ values reported in that interconnection.

Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data. Until the BAL-003-1 process outlined in Attachment 1 is implemented, Balancing Authorities can approximate their FRO by multiplying their Interconnection's FRO by their share of Interconnection Bias. The data used for this calculation should be for 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 merge or that transfer load or generation need to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation for the Interconnection remains the same and so that CPS limits can be adjusted.

Attachment A proposes the following Interconnection event criteria as a basis to determine an Interconnection's Frequency Response Obligation:

- Largest category C loss-of-resource (N-2) event.
- Largest total generating plant with common voltage switchyard.
- Largest loss of generation in the interconnection in the last 10 years.

With regard to the second objective above (determining Frequency Bias Settings and CPS limits), Balancing Authorities have been asked to perform annual reviews of their Frequency Bias Settings by measuring their Frequency Response, dating back to Policy 1. This obligation was carried forward into BAL-003-01.b. While the associated training document provided useful information, it left many of the details to the judgment of the person doing the analysis. The FRS Form 1 and FRS Form 2 provide a consistent, objective process for calculating Frequency Response to develop an annual measure, the FRM.

The FRM will be computed from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event from a Balancing Authority that is used to calculate its Frequency Response, expressed in MW/0.1Hz". The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is basically the change of 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 values to account for factors such as nonconforming loads. FRS Form 1 shows the types of adjustments that are allowed.)

A standardized sampling interval of approximately 20 to 52 seconds will be used in the computation of SEFRD values. Microsoft Excel® spreadsheet interfaces for EMS scan rates of 2 through 6 seconds are provided to support the computation.

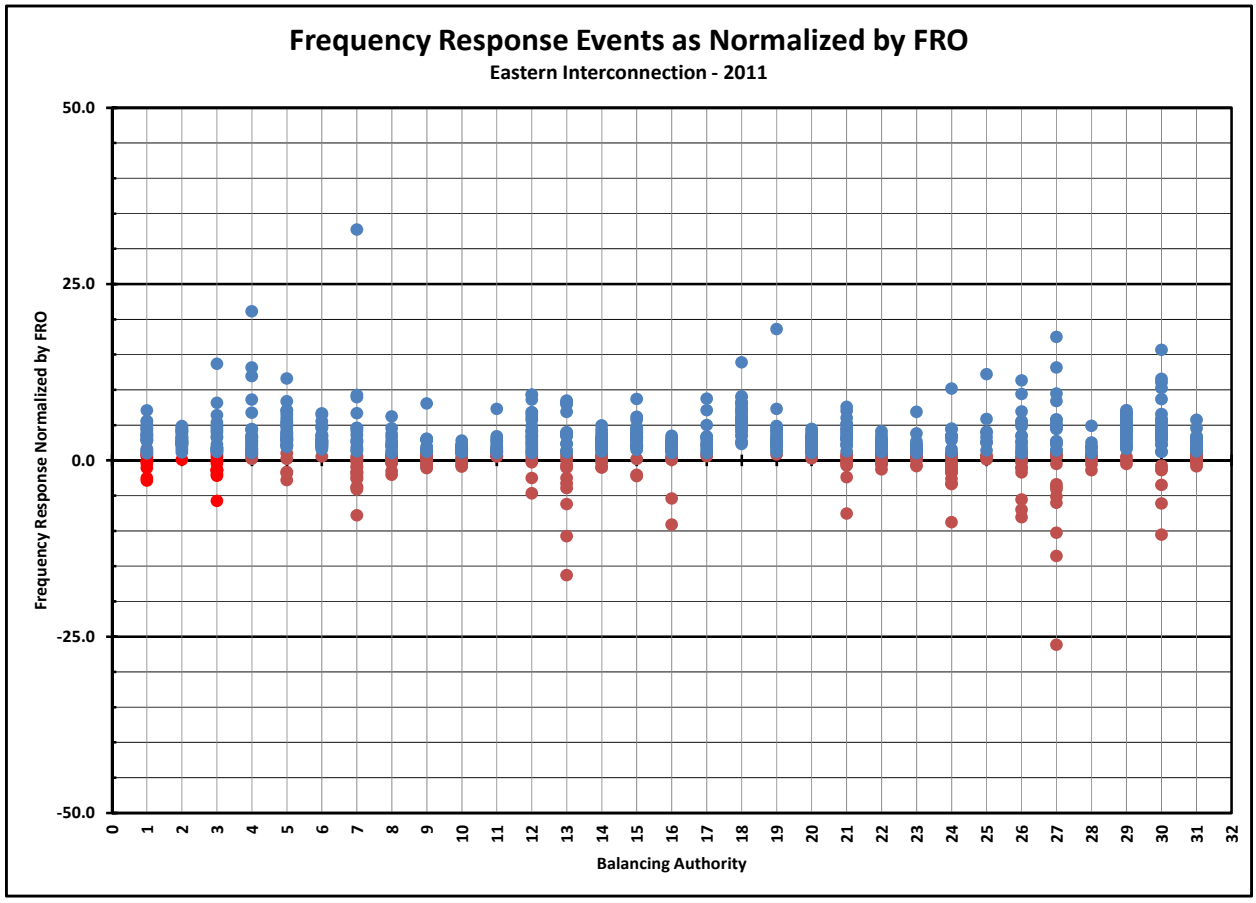
Single Event Frequency Response Data[8]

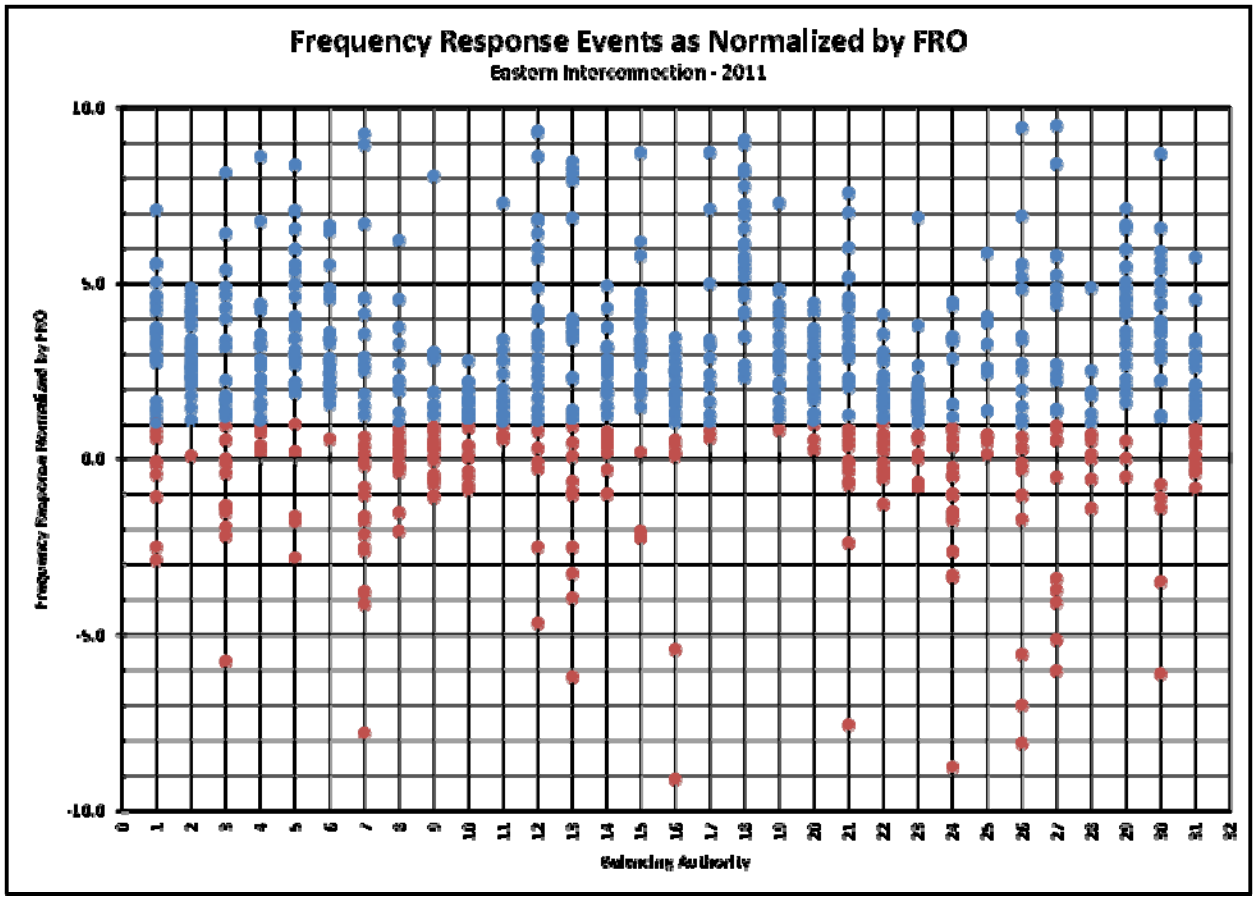
The use of a "single event measure" was considered early in the development of the FRS for compliance because a single event measure could be enforced for each event on the interconnection making compliance enforcement a simpler process. The variability of the measurement of Frequency Response for an individual BA for an individual Disturbance event was evaluated to determine its suitability for use as a compliance measure. The individual Disturbance events were normalized and plotted for each BA on the Eastern and Western Interconnections. This data was plotted with a dot representing each event. Events with a measured Frequency Response above the FRO were shown as blue dots and events with a measured Frequency Response below the FRO were shown as red dots. In order to show the full variability of the results the plots have been provided with two scales, a large scale to show all of the events and small scale to show the events closer to the FRO or a value of 1.0. This data is presented on four charts titled Frequency Response Events as Normalized by FRO.

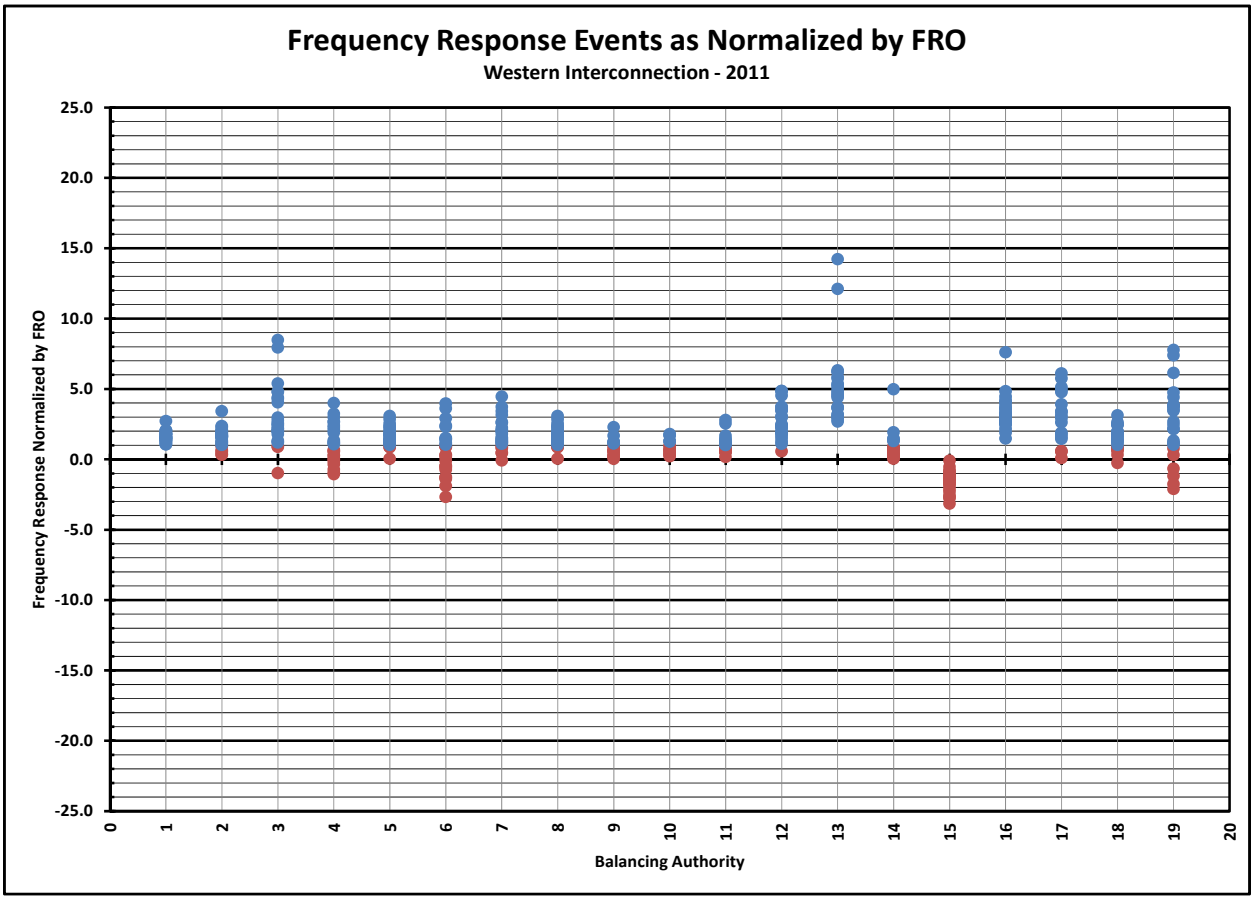
Analysis of this data indicates a single event based compliance measure is unsuitable for compliance evaluation when the data has the large degree of variability shown in these charts. Based on the field trial data provided, only 3 out of 19 BAs on the Western Interconnection would be compliant for all events with a standard based on a single event measure. Only 1 out of 31 BAs on the Eastern Interconnection would be compliant for all events with a standard based on a single event measure. The general consensus of the industry is that there is not a reliability issue with insufficient Frequency Response on any of the North American Interconnections at this time. Therefore, it is unreasonable to even consider a standard that would indicate over 90% of the BAs in North American to be non-compliant with respect to maintaining sufficient Frequency Response to maintain adequate reliability.

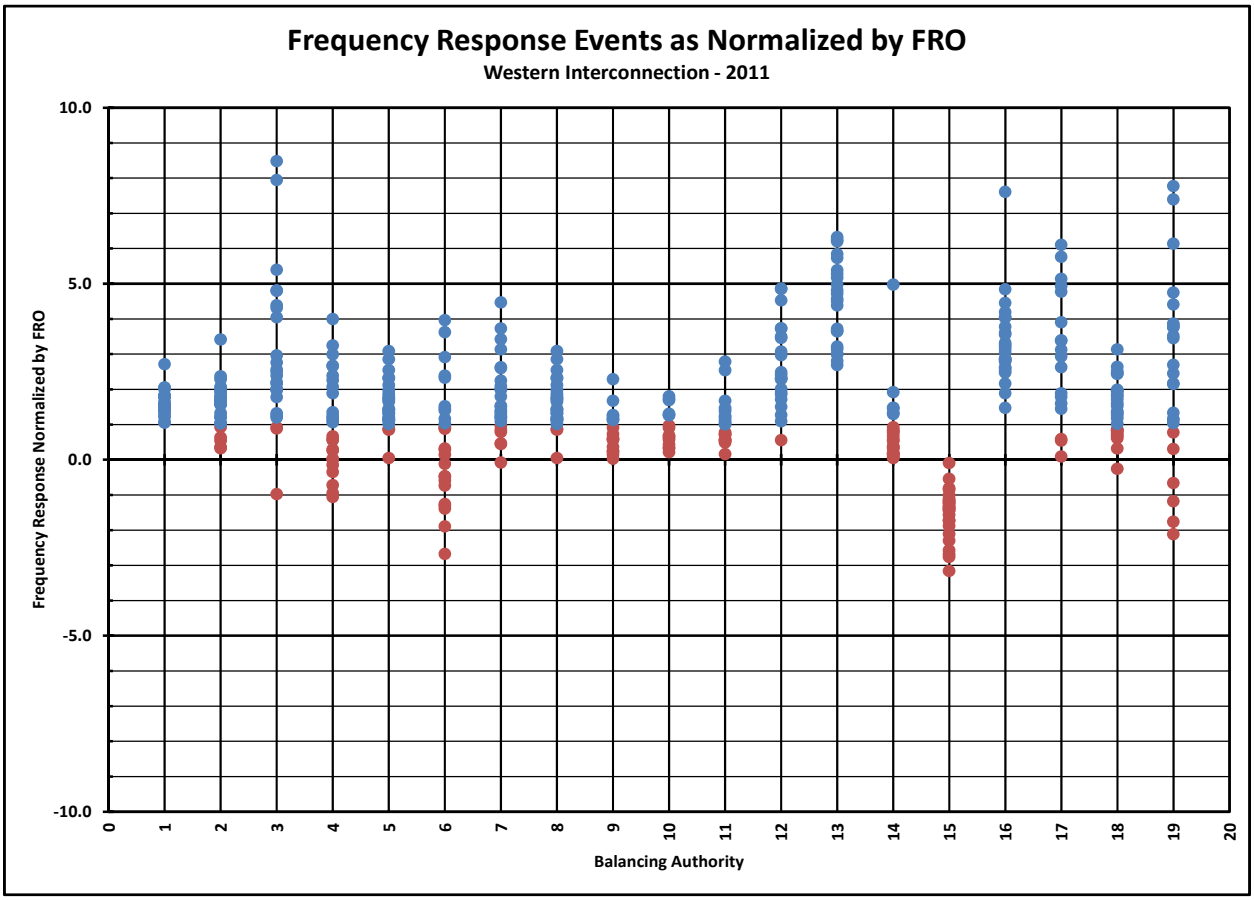
In an attempt to balance the workload of Balancing Authorities with the need for accuracy in the FRM, the standard will require at least 20 samples selected during the course of the year to compute the FRM. Research conducted by the FRSDT indicated that a Balancing Authority's FRM will converge to a reasonably stable value with at least 20 samples.

[8] Single Event Analysis based on results of Frequency Response Standard Field Trial Analysis, September 17, 2012.


Frequency Response Events as Normalized by FRO
Eastern Interconnection - 2011
Frequency Response Normalized by FRO
50.0
25.0
0.0
-25.0
-50.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32
Balancing Authority


Frequency Response Events as Normalized by FRO
Eastern Interconnection - 2011
10.0
5.0
0.0
-5.0
-10.0


Frequency Response Events as Normalized by FRO
Western Interconnection - 2011
Frequency Response Normalized by FRO
25.0
20.0
15.0
10.0
5.0
0.0
-5.0
-10.0
-15.0
-20.0
-25.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Balancing Authority


Frequency Response Events as Normalized by FRO
Western Interconnection - 2011
Frequency Response Normalized by FRO
10.0
5.0
0.0
-5.0
-10.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Balancing Authority

Sample Size
In order to support field trial evaluations of sample size, sampling intervals, and aggregation techniques, the FRSDT will be retrieving scan rate data from the Balancing Authorities for each SEFRD. Additional frequency events may also be requested for research purposes, though they will not be included in the FRM computation.

FERC Order No. 693 directed the ERO (at P 375) to define the number of Frequency Response surveys that were conducted each year and to define a necessary amount of Frequency Response. R1 addresses both of these directives:

- There is a single annual survey of at least 20 events each year.
- The FRM calculated on FRS Form 1 is compared by the ERO against the FRO determined 12 months earlier (when the last FRS Form 1 was submitted) to verify the Balancing Authority provided its share of Interconnection Frequency Response.

Median as the Standard's Measure of Balancing Authority Performance
The FRSDT evaluated different approaches for "averaging" individual event observations to compute a technically sound estimate of Frequency Response Measure. The MW contribution for a single BA in a multi-BA Interconnection is small compared to the minute to minute changes in load, interchange and generation. For example, a 3000 MW BA in the Eastern Interconnection may only be called on to contribute 10MW for the loss of a 1000MW. The 10 MW of governor and load response may easily be masked as a coincident change in load.

In general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FRSDT has shown the Median to be less influenced by noise in the measurement process and the team has chosen the median as the initial metric for calculating the BAs' Frequency Response Measure.

The FRSDT performed extensive empirical studies and engaged in lively discussions in an attempt to determine the best aggregation technique for a sample set size of at least 20 events. Mean, median, and linear regression techniques were used on a trial basis with the data that was available during the early phases of the effort.

A key characteristic of the "aggregation challenge" is related to the use of actual net interchange data for measuring frequency response. The tie line flow measurements are varying continuously due to other operational phenomena occurring concurrently with the provision of frequency response. (*See* Appendix 1 for details.) All samples have "noise" in them, as most operational personnel who have computed the frequency response of their BA can attest. What has also become apparent to the FRSDT is that while the majority of the frequency response samples have similar levels of noise in them, a few of the samples may have much larger errors in them than the others that result in unrepresentative results. And with the sample set size of interest, it is common to have unrepresentative errors in these few samples to be very large and asymmetric. For example, one BA's subject matter expert observed recently that 4 out of 31 samples had a much larger error contribution than the other 27 samples, and that 3 out of 4 of the very high error samples grossly underestimated the frequency response. The median value demonstrated greater resiliency to this data quality problem than the mean with this data set. (The median has also demonstrated superiority to

linear regression in the presence of these described data quality problems in other analyses conducted by the FRSDT, but the linear regression showed better performance than the mean.)

The above can be demonstrated with a relatively simple example. Let's assume that a Balancing Authority's true frequency response has an average value of -200 MW/ .1 Hz. Let's also assume that this Balancing Authority installed "special" perfect metering on key loads and generators, so that we could know the true frequency response of each sample. And then we will compare them with that measured by typical tie line flow metering, with the kind of noise and error that occurs commonly and "not so commonly". Let's start with the following 4 samples having a common level of noise, with MW/ .1 Hz as the unit of measurement.

Perfect measurement	Noise	Samples from tie lines
-190	-30	-220
-210	-20	-230
-220	10	-210
-180	20	-160
-200	Mean	-205
-200	Median	-215

Now let's add a fifth sample, which is highly contaminated with noise and error that grossly underestimates frequency response.

Perfect measurement	Noise	Samples from tie lines
-190	-30	-220
-210	-20	-230
-220	10	-210
-180	20	-160
-200	250	+50
-200	Mean	-154
-200	Median	-210

It is clear from the above simplistic example that the mean drops by about 25% while the median is affected minimally by the single highly contaminated value.

Based on the analyses performed thus far, the FRSDT believes that the median's superior resiliency to this type of data quality problem makes it the best aggregation technique at this time. However, the FRSDT sees merit and promise in future research with sample filtering combined with a technique such as linear regression.

When compared with the mean, linear regression shows superior performance with respect to the elimination of noise because the measured data is weighted by the size of the frequency change associated with the event. Since the noise is independent from frequency change, the greater weighting on larger events provides a superior technique for reducing the effect of noise on the results.

However, linear regression does not provide a better method when dealing with a few samples with large magnitudes of noise and unrepresentative error. There are only two alternatives to improve over the use of median when dealing with these larger unrepresentative errors:

1. Increase the sample size, or
2. Actively eliminate outliers due to unrepresentative error.

Unfortunately, the first alternative, increasing the sample size is not available because significantly more sample events are not available within the measurement time period of one year. Linear regression techniques are being investigated that have an active outlier elimination algorithm that would eliminate data that lie outside ranges of the 96th percentile and 99th percentile, for example.

Still, the use of linear regression has value in the context of this standard. The NERC Resources Subcommittee will use linear regression to evaluate Interconnection frequency response, particularly to evaluate trends, seasonal impacts, time of day influences, etc. The Good Practices and Tools section of this document outlines how a BA can use linear regression to develop a predictive tool for its operators.

Additional discussion on this topic is contained in "Appendix 1 – Data Quality Concerns Related to the Use of Actual Net Interchange Value" of this document.

The NERC Frequency Response Initiative Report addressed the relative merits of using the median versus linear regression for aggregating single event frequency response samples into a frequency response measurement score for compliance evaluation. This report provided 11 evaluation criteria as a basis for recommending the use of linear regression instead of the median for the frequency response measurement aggregation technique. The FRSDT made its own assessment on the basis of these evaluation criteria on September 20, 2012, but concluded that the median would be the best aggregation technique to use initially when the relative importance of each criterion was considered. A brief summary of the FRSDT majority consensus on the basis of each evaluation criterion is provided below.

- Provides two dimensional measurement – The FRSDT agrees that the two dimensional concept is a useful way to perceive frequency response characteristics, and that it may be useful for potential future modeling activities. Better data quality would increase support for such future efforts, and the use of the median for initial compliance evaluations within BAL-003-1 should not hinder any such effort. The FRSDT perceived this as a mild advantage for linear regression.
- Represents nonlinear characteristics – With considerations similar to those applied to the previous criterion, the FRSDT perceived this as a mild advantage for linear regression.
- Provides a single best estimator – The FRSDT gave minimal importance to the characteristic of the median averaging the middle values when used with an even number of samples.
- Is part of a linear system - With considerations similar to those applied to the first two criteria, the FRSDT perceived this as a mild advantage for linear regression (particularly in the modeling area.)
- Represents bimodal distributions – The FRSDT gave minimal weight of this criterion, as a change in Balancing Authority footprint does not seem to be addressed adequately by any aggregation technique.
- Quality statistics available – The FRSDT perceived this as a mild advantage for linear regression in that the statistics would be coupled directly to the compliance evaluation. The FRSDT also included this criterion as part of the modeling advantages cited above.

The FRSDT supports collecting data and performing quality statistical analysis. If it is determined that the use of the median, as opposed to a mean or linear regression aggregation, is yielding undesirable consequences, the FRSDT recommends that other aggregation techniques be re-evaluated at that time.

- Reducing influence of noise - This is the dominant concern of the FRSDT, and it perceives the median to have a major advantage over linear regression in addressing noise in the change in actual net interchange calculation. The FRSDT bases this judgment on: prior FRSDT studies that have shown that the median produces more stable results; the data used in the NERC Frequency Response Initiative document exhibits large quantities of noise; prior efforts of FRSDT members in performing frequency response sampling for their own Balancing Authorities over many years; and similar observations of noise in the CERTS frequency Monitoring Application. The FRSDT has serious concerns that the influence of noise has a greater tendency to yield a "false positive" compliance violation with linear regression than with the median. Also, limited studies performed by the FRSDT indicates the possibility that the resultant frequency response measure would yield more measurement variation across years with linear regression versus the median while the actual Balancing Authority performance remains unchanged.
- Reducing the influence of outliers – This is related to the previous criterion. The FRSDT recognizes four main sources of noise: concurrent operating phenomena (described elsewhere in this document), transient tie line flows for nearby contingencies, data acquisition time skew in tie line data measurements, and time skew and data compression issues in archiving techniques and tools such as PI. Some outliers may be caused in part by true variation in the actual frequency response, and it is desirable to include those in the frequency response measure. The FRSDT supports efforts in the near future to distinguish between outliers caused by noise versus true frequency response, and progress in this area may make it feasible and desirable to replace the median with linear regression, or some other validated technique. The FRSDT does note that this is a substantial undertaking, and it would require substantial input from a sufficient number of experts to help distinguish noise from true frequency response.
- Easy to calculate – The FRSDT perceives this to be a minor to moderate advantage for the median. However, more complex (but reasonably so) techniques would receive more support if clear progress can be made in noise elimination.
- Familiar indicator – The FRSDT perceives this to be a minor to moderate advantage for the median. However, more complex (but reasonably so) techniques would receive more support if clear progress can be made as a result of noise elimination.
- Currently used as a measure in BAL-003 – The present standard refers to an average and does not provide specific guidance on the computation of that average, but the FRSDT puts minimal weight on this evaluation criterion.

In summary, the FRSDT perceives an approximate balance between the modeling advantage for linear regression and the simplicity advantage of the median. However, the clear determinant in endorsing the use of the median is the data quality issue related to concurrent operational phenomena, transient tie line flows, and data acquisition and archiving limitations.

FERC Order No. 693 also directed the Standard (at P 375) to identify methods for Balancing Authorities to obtain Frequency Response. Requirement R1 allows Balancing Authorities to participate in Frequency Response Sharing Groups (FRSGs) to provide or obtain Frequency Response. These may be the same FRSGs that cooperate for BAL-002-0 or may be FRSGs that form for the purposes of BAL-003-1.

If BAs participate as an FRSG for BAL-003-1, compliance is based on the sum of the participants' performance.

Two other ways that BAs could obtain Frequency Response are through Supplemental Service or Overlap Regulation Service:

- No special action is needed if a BA provides or receives supplemental regulation. If the regulation occurs via Pseudo Tie, the transfer occurs automatically as part of Net Actual Interchange (NIA) and in response to information transferred from recipient to provider.
- If a BA provides overlap regulation, its FRS Form 1 will include the Frequency Bias setting as well as peak load and generation of the combined Balancing Authority Areas. The FRM event data will be calculated on the sum of the provider's and recipient's performance.

In the Violation Severity Levels for Requirement R1, the impact of a BA not having enough frequency response depends on two factors:

- Does the Interconnection have sufficient response?
- How short is the BA in providing its FRO?

The VSL takes these factors into account. While the VSLs look different than some other standards, an explanation would be helpful.

VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plane as single-BA Interconnections.

Consider a small BA whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response, because this would treat multi-BA Interconnections more harshly than single BA Interconnections on a significant scale.

The "Lower" and "Medium" VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively.

Requirement 2

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.

Background and Rationale

Attachment A of the Standard discusses the process the ERO will follow to validate the BA's FRS Form 1 data and publish the official Frequency Bias Settings. Historically, it has taken multiple rounds of validation and outreach to confirm each BA's data due to transcription errors, misunderstanding of instructions, and other issues. While BAs historically submit Bias Setting data by January 1, it often takes one or more months to complete the process.

The target is to have BAs submit their data by January 10. The BAs are given 30 days to assemble their data since the BAs are dependent on the ERO to provide them with FRS Form 1, and there may be process delays in distributing the forms since they rely on identification of frequency events through November 30 of the preceding year.

Frequency Bias Settings generally change little from year to year. Given the fact that BAs can encounter staffing or EMS change issues coincident with the date the ERO sets for new Frequency Bias Setting implementation, the standard provides a 24 hour window on each side of the target date.

To recap the annual process:

1. The ERO posts the official list of frequency events to be used for this Standard in early December. The FRS Form 1 for each Interconnection will be posted shortly thereafter.

2. The Balancing Authority submits its revised annual Frequency Bias Setting value to NERC by January 10.

3. The ERO and the Resources Subcommittee validate Frequency Bias Setting values, perform error checking, and calculate, validate, and update CPS2 L10 values. This data collection and validation process can take as long as two months.

4. Once the L10 and Frequency Bias Setting values are validated, The ERO posts the values for the upcoming year and also informs the Balancing Authorities of the date on which to implement revised Frequency Bias Setting values. Implementation typically would be on or about March 1st of each year.

BAL-003-0.1b standard requires a minimum Frequency Bias Setting equal in absolute value to one percent of the Balancing Authority's estimated yearly peak demand (or maximum generation level if native load is not served). For most Balancing Authorities this calculated amount of Frequency Bias is significantly greater in absolute value than their actual Frequency Response characteristic (which represents an over-bias condition) resulting in over-control

since a larger magnitude response is realized. This is especially true in the Eastern Interconnection where this condition requires excessive secondary frequency control response which degrades overall system performance and increases operating cost as compared to requiring an appropriate balance of primary and secondary frequency control response.

Balancing Authorities were given a minimum Frequency Bias Setting obligation because there had never been a mandatory Frequency Response Obligation. This historic "one percent of peak per 0.1Hz" obligation, dating back to NERC's predecessor, NAPSIC, was intended to ensure all BAs provide some support to Interconnection frequency.

The ideal system control state exists when the Frequency Bias Setting of the Balancing Authority exactly matches the actual Frequency Response characteristic of the Balancing Authority. If this is not achievable, over-bias is significantly better from a control perspective than under-bias with the caveat that Frequency Bias is set relatively close in magnitude to the Balancing Authority actual Frequency Response characteristic. Setting the Frequency Bias to better approximate the Balancing Authority natural Frequency Response characteristic will improve the quality and accuracy of ACE control, CPS & DCS and general AGC System control response. This is the technical basis for recommending an adjustment to the long standing "1% of peak/0.1Hz" Frequency Bias Setting. The Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard is intended to bring the Balancing Authorities' Frequency Bias Setting closer to their natural Frequency Response. Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard balances the following objectives:

- Bring the Frequency Bias Setting and Frequency Response closer together.
- Allow time to analyze impact on other Standards (CPS, BAAL and to a lesser extent DCS) by adjustments in the minimum Frequency Bias Setting, by accommodating only minor adjustments.
- Do not allow the Frequency Bias Setting minimum to drop below natural Frequency Response, because under-biasing could affect an Interconnection adversely.

Additional flexibility has been added to the Frequency Bias Setting based on the actual Frequency Response (FRM) by allowing the Frequency Bias Setting to have a value in the range from 100% of FRM to 125% of FRM. This change has been included for the following reasons:

- When the new standardized measurement method is applied to BAs with a Frequency Response close to the interconnection minimum response, the requirement to use FRM is as likely to result in a Frequency Bias Setting below the actual response as it is to result in a response above the actual response. From a reliability perspective, it is

always better to have a Frequency Bias Setting slightly above the actual Frequency Response.

- As with single BA interconnections, the tuning of the control system may require that the BA implement a Frequency Response Setting slightly greater in absolute terms than its actual Frequency Response to get the best performance.
- The new standardized measurement method for determining FRM in some cases results in a measured Frequency Response significantly lower than the previous methods used by some BAs. It is desirable to not require significant change in the Frequency Bias Setting for these BAs that experience a reduction in their measured Frequency Response.

Requirement 3

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is:

- *Less than zero at all times, and*
- *Equal to or more negative than its Frequency Response Obligation when the Frequency varies from 60 Hz by more that +/- 0.036 Hz.*

Background and Rationale

In multi-Balancing Authority interconnections, the Frequency Bias Setting should be coordinated among all BAs on the interconnection. When there is a minimum Frequency Bias Setting requirement, it should apply for all BAs. However, BAs using a variable Frequency Bias Setting may have non-linearity in their actual response for a number of reasons including the dead-bands implemented on their generator governors. The measurement to ensure that these BAs are conforming to the interconnection minimum is adjusted to remove the dead-band range from the calculated average Frequency Bias Setting actually used. For BAs using variable bias, FRS Form 1 has a data entry location for the previous year's average monthly Bias. The Balancing Authority and the ERO can compare this value to the previous year's Frequency Bias Setting minimum to ensure R3 has been met.

On single BA interconnections, there is no need to coordinate the Frequency Bias Setting with other BAs. This eliminates the need to maintain a minimum Frequency Bias Setting for any reason other than meeting the reliability requirement as specified by the Frequency Response Obligation.

Requirement 4

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:

- *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 as shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.*

Background and Rationale

This requirement reflects the operating principles first established by NERC Policy 1 and is similar to Requirement R6 of the approved BAL-003-0.1b standard. Overlap Regulation Service is a method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into the providing Balancing Authority's AGC/ACE equation.

As noted earlier, a BA that is providing Overlap Regulation will report the sum of the Bias Settings in its FRS Form 1. Balancing Authorities receiving Overlap Regulation Service have an ACE and Frequency Bias Setting equal to zero (0).

How this Standard Meets the FERC Order No. 693 Directives

FERC Directive

The following is the relevant paragraph of Order No. 693.

> *Accordingly, the Commission approves Reliability Standard BAL-003-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to BAL-003-0 through the Reliability Standards development process that: (1) includes Levels of Non-Compliance; (2) determines the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met, and to modify Measure M1 based on that determination and (3) defines the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved.*

1. Levels of Non-Compliance

VRFs and VSLs are an equally effective way of assigning compliance elements to the standard.

2. Determine the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other Requirements of the Reliability Standard are met

BAL-003 V0 R2 (the basis of Order No. 693) deals with the calculation of Frequency Bias Setting such that it reflects natural Frequency Response.

The drafting team has determined that a sample size on the order of at least 20 events is necessary to have a high confidence in the estimate of a BA's Frequency Response. Selection of the frequency excursion events used for analysis will be done via a method outlined in Attachment A to the Standard.

On average, these events will represent the largest 2-3 "clean" frequency excursions occurring each month.

Since Frequency Bias Setting is an annual obligation, the survey of the at least 20 frequency excursion events will occur once each year.

3. Define the necessary amount of Frequency Response needed for Reliable Operation for each Balancing Authority with methods of obtaining and measuring that the frequency response is achieved

Necessary Amount of Frequency Response

The drafting team has proposed the following approach to defining the necessary amount of frequency response. In general, the goal is to avoid triggering the first step of under-frequency load shedding (UFLS) in the given Interconnection for reasonable contingencies expected. The

methodology for determining each Interconnection's and Balancing Authority's obligation is outlined in Attachment A to the Standard.

It should be noted the standard cannot guarantee there will never be a triggering of UFLS as the magnitude of "point C" differs throughout an interconnection during a disturbance and there are local areas that see much wider swings in frequency.

The contingency protection criterion is the largest reasonably expected contingency in the Interconnection. This can be based on the largest observed credible contingency in the previous 10 years or the largest Category C event for the Interconnection.

Attachment A to the standard presents the base obligation by Interconnection and adds a Reliability Margin. The Reliability Margin included addresses the difference between Points B and C and accounts for variables.

For multiple BA interconnections, the Frequency Response Obligation is allocated to BAs based on size. This allocation will be based on the following calculation:

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

Methods of Obtaining Frequency Response

The drafting team believes the following are valid methods of obtaining Frequency Response:

- Regulation services.
- Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration.
- Through a tariff (e.g. Frequency Response and regulation service).
- From generators through an interconnection agreement.
- Contract with an internal resource or loads (The drafting team encourages the development of a NAESB business practice for Frequency Response service for linear (droop) and stepped (e.g. LaaR in Texas) response).

Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.

Measuring that the Frequency Response is Achieved

FRS Form 1 and the underlying data retained by the BA will be used for measuring whether Frequency Response was provided. FRS Form 1 will provide the guidance on how to account for and measure Frequency Response.

Going Beyond the Directive

Based on the combined operating experience of the SDT, the drafting team consensus is that each Interconnection has sufficient Frequency Response. If margins decline, there may be a need for additional standards or tools. The drafting team and the Resources Subcommittee are working with the ERO on its Frequency Response Initiative to develop processes and good practices so the Interconnections are prepared. These good practices and tools are described in the following section.

The drafting team is also evaluating a risk-based approach for basing the Interconnection Frequency Response Obligation on an historic probability density of frequency error, and for allocating the obligation on the basis of the Balancing Authority's average annual ACE share of frequency error. This allocation method uses the inverse of the rationale for allocating the CPS1 epsilon requirement by Bias share.

Good Practices and Tools

Background

This section outlines tips and tools to help Balancing authorities meet the Frequency Response Standard or to operate more reliably. If you have suggested additions, please send them to balancing@nerc.com.

Identifying and Estimating Frequency Responsive Reserves

Knowing the quantity and depth of frequency responsive reserves in real time is a possible next step to being better prepared for the next event. The challenge in achieving this is having the knowledge of the capabilities of all sources of frequency response. Presently the primary source of Frequency Response remains with the generation resources in our fleets.

Understanding how each of these sources performs to changes in system frequency and knowing their limitations would improve the BA's ability to measure frequency responsive reserves. Presently there are only guidelines, criteria and protocols in some regions of the industry that identify specific settings and performance expectations of Primary Frequency Response of resources.

One method of gaining a better understanding of performance is to measure performance during actual events that occur on the system. Measuring performance during actual events would only provide feedback for performance during that specific event and would not provide insight into depth of response or other limitations.

Repeated measurements will increase confidence in expected performance. NERC modeling standards are in process to be revised that will improve the BA's insight into predicting available frequency responsive reserves. However, knowing how resources are operated, what modes of operation provide sustained Primary Frequency Response and knowing the operating range of this response would give the BA the knowledge to accurately predict frequency response and the amount of frequency responsive reserves available in real time.

Some benefits have been realized by communicating to generation resources (GO) the importance of operating in modes that allow Primary Frequency Response to be sustained by the control systems of the resource. Other improvements in implementation of Primary Frequency Response have been achieved through improved settings on turbine governors through the elimination of "step" frequency response with the simultaneous reduction in governor dead-band settings.

Improvements in the full AGC control loop of the generating resource, which accounts for the expected Primary Frequency Response, have improved the delivery of quality Primary Frequency Response while minimizing secondary control actions of generators. Some of these actions can provide quick improvement in delivery of Primary Frequency Response.

Once Primary Frequency Response sources are known, the BA could calculate available reserves that are frequency responsive. Planning for these reserves during normal and emergency operations could be developed and added to the normal planning process.

Using FRS Form 1 Data

The information collected for this standard can be supplemented by a few data points to provide the Balancing Authority useful tools and information. The BA could do a regression analysis of its frequency response against the following values:

- Load (value A).
- Interchange (Value A).
- Total generation.
- Spinning reserve.

While the last two values above are not part of Form 1, they should be readily available. Small BAs might even include headroom on its larger generators as part of the regression.

The regression would provide a formula the BA could program in its EMS to present the operator a real time estimate of the BA's Frequency Response.

Statistical outliers in the regression would point to cases meriting further inspection to find causes of low Frequency Response or opportunities for improvement.

Tools

Single generating resource performance evaluation tools for steam turbine, combustion turbine (simple cycle or combined cycle) and for intermittent resources are available at the following link. http://texasre.org/standards_rules/standardsdev/rsc/sar003/Pages/Default.aspx.

These tools and the regional standard associated with them are in their final stages of development in the Texas region.

These tools will be posted on the NERC website.

References

NERC *Frequency Response Characteristic Survey Training Document* (Found in the NERC Operating Manual)

NERC Resources Subcommittee Position Paper on Frequency Response

NERC TIS Report *Interconnection Criteria for Frequency Response Requirements (for the Determination Interconnection Frequency Response Obligations (IFRO)*

Frequency Response Standard Field Trial Analysis, September 17, 2012

Appendix 1 - Data Quality Concerns Related To The Use Of The Actual Net Interchange Value

Actual net interchange for a typical Balancing Authority (BA) is the summation of its tie lines to other BAs. In some cases, there are pseudo-ties in it which reflect the effective removal or addition of load and/or generation from another BA, or it could include supplemental regulation as well. But in the typical scenario, actual net interchange values that are extracted from EMS data archiving can be influenced by data latency times in the data acquisition process, and also any timestamp skewing in the archival process.

Of greater concern, however, are the inevitable variations of other operating phenomena occurring concurrently with a frequency event. The impacts of these phenomena are superimposed on actual net interchange values along with the frequency response that we wish to measure through the use of the actual net interchange value.

To explore this issue further, let's begin with the idealized condition:

- frequency is fairly stable at some value near or a little below 60 Hz
- ACE of the non-contingent BA of interest is 0 and has been 0 for an extended period, and AGC control signals have not been issued recently
- Actual net interchange is "on schedule", and there are no schedule changes in the immediate future
- BA load is flat
- All generators not providing AGC are at their targets
- Variable generation such as wind and solar are not varying
- Operators have not directed any manual movements of generation recently

And when the contingency occurs in this idealized state, the change in actual net interchange will be measuring only the decline in load due to lesser frequency and generator governor response, and, none of the contaminating influences. While the ACE may become negative due to the actual frequency response being less than that called for by the frequency bias setting within the BA's AGC system, this contaminating influence on measuring frequency response will not appear in the actual net interchange value if the measurement interval ends before the generation on AGC responds.

Now let's explore the sensitivity of the resultant frequency response sampling to the relaxation of these idealized circumstances.

1. The "60 Hz load" increases moderately due to time of day concurrent with the frequency event. If the frequency event happens before AGC or operator-directed manual load adjustments occur, then the actual net interchange will be reduced by the moderate increase in load and the frequency response will be underestimated. But if the frequency event happens while AGC response and/or manual adjustments occur, then the actual net interchange will be increased by the AGC response (and/or manual adjustments) and the frequency response will be overestimated.

2. The “60 Hz load” decreases moderately due to time of day concurrent with the frequency event. If the frequency event happens before AGC or operator-directed manual load adjustments occur, then the actual net interchange will be increased by the moderate reduction in load and the frequency response will be overestimated. But if the frequency event happens while AGC response and/or manual adjustments occur, then the actual net interchange will be decreased by the AGC response (and/or manual adjustments) and the frequency response will be underestimated.
3. In anticipation of increasing load during the next hour, the operator increases manual generation before the load actually appears. If the frequency event happens while the generation “leading” the load is increasing, then the actual net interchange will be increased by the increase in manual generation and the frequency response will be overestimated. But if the frequency event occurs when the result of AGC signals sent to offset the operator’s leading actions take effect, then the actual net interchange will be decreased and the frequency response is underestimated.
4. In anticipation of decreasing load during the next hour, the operator decreases manual generation before the load actually declines. If the frequency event happens while the generation “leading” the load downward is decreasing, then the actual net interchange will be decreased by the reduction in manual generation and the frequency response will be underestimated. But if the frequency event occurs when the result of AGC signals sent to offset the operator’s leading actions take effect, then the actual net interchange will be increased and the frequency response is overestimated.
5. A schedule change to export more energy is made at 5 minutes before the top of the hour. The BA’s “60 Hz load” is not changing. The schedule change is small enough that the operator is relying on upward movement of generators on AGC to provide the additional energy to be exported. The time at which the AGC generators actually begin to provide the additional energy is dependent on how much time passes before the AGC algorithm gets out of its deadbands, the individual generator control errors get large enough for sending out the control signal, and maybe 20 seconds to 3 minutes for the response to be effected. The key point here is that it is not clear when the effects of a schedule change, as manifested in a change in generation and then ultimately a change in actual net interchange, will occur.
6. With the expected penetration of wind in the near future, unanticipated changes in their output will tend to affect actual net interchange and add noise to the frequency response observation process.

To a greater or lesser extent, 1 through 4 above are happening continuously for the most part with most BAs in the Eastern and Western Interconnections. The frequency response is buried within the typical hour to hour operational cacophony superimposed on actual net interchange values. The choice of metrics will be important to artfully extract frequency response from the noise and other unrepresentative error.

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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.

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

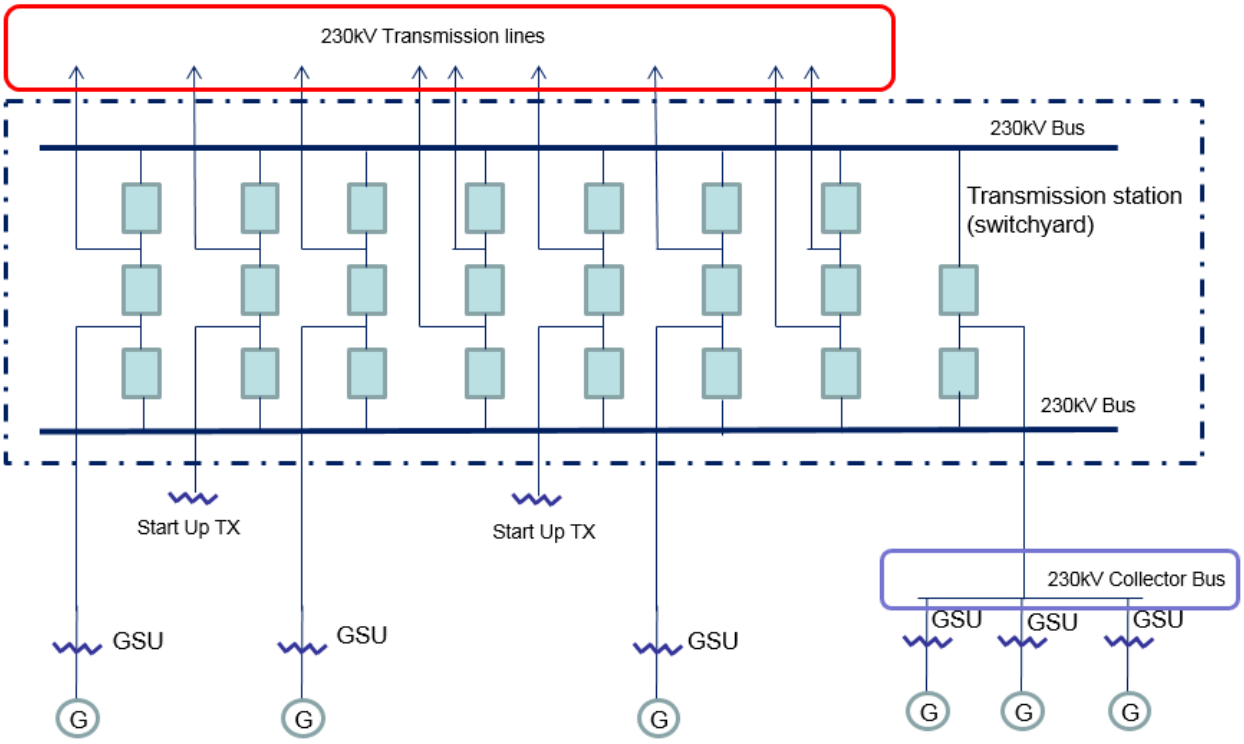
The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within 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:

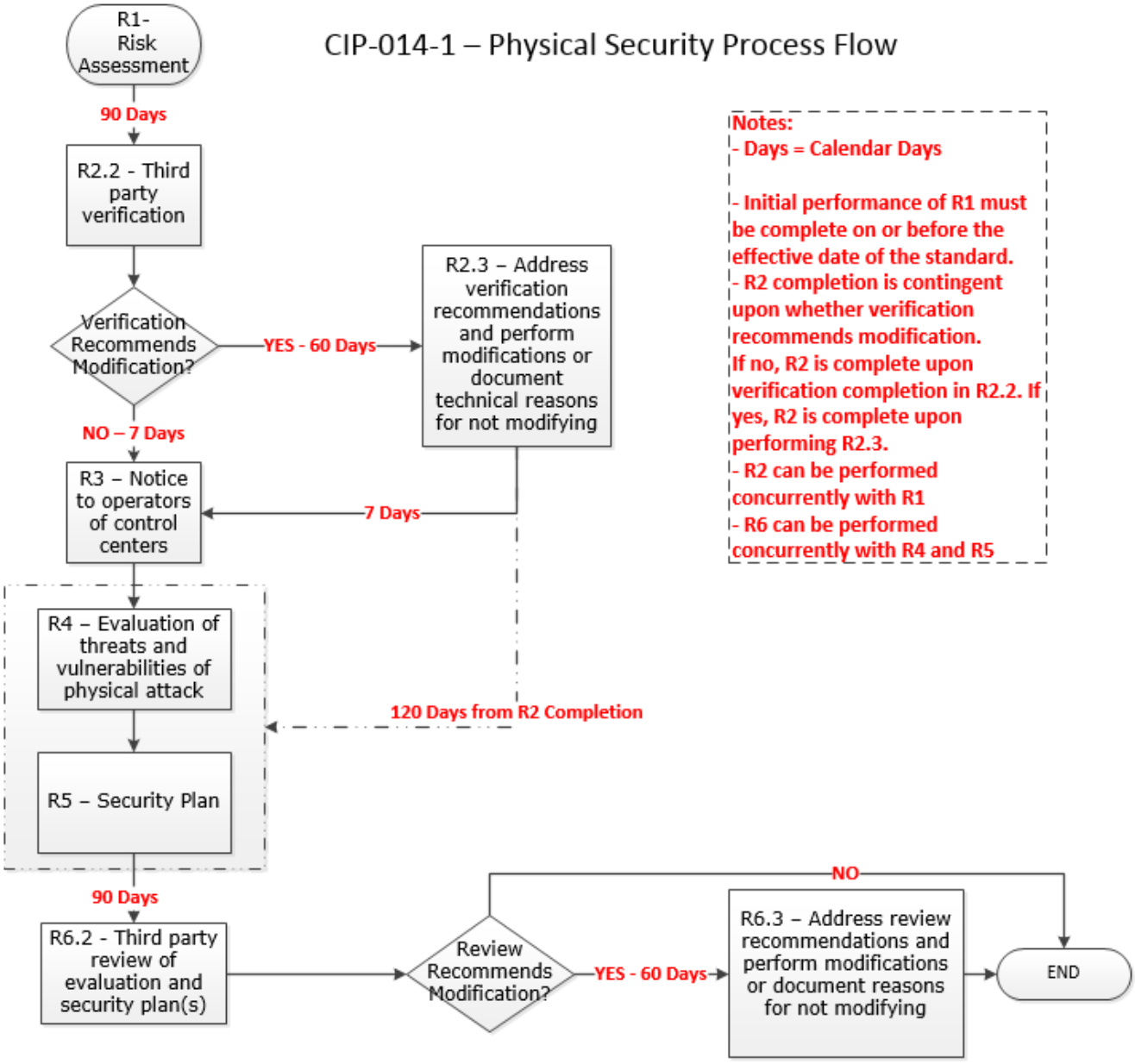
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

  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
7 Days
R3 – Notice to operators of control centers
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
NO
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
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.

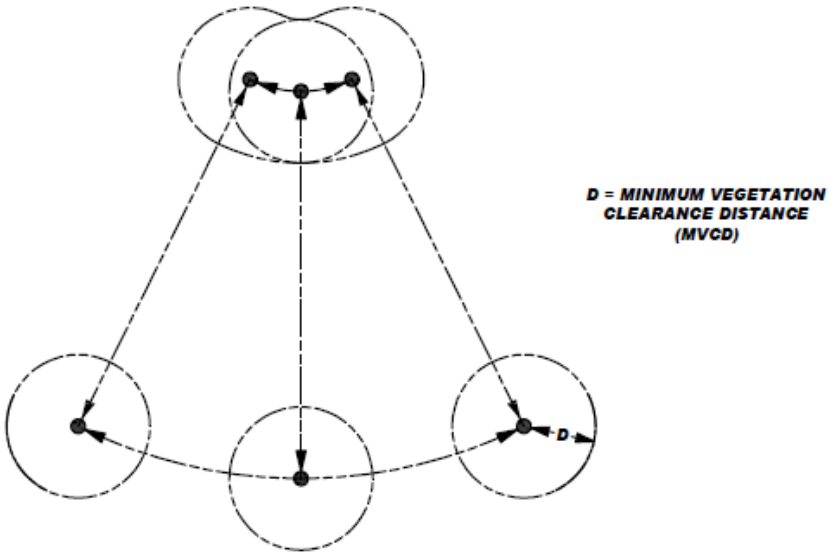


Figure 1

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.

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[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.

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[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

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[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.

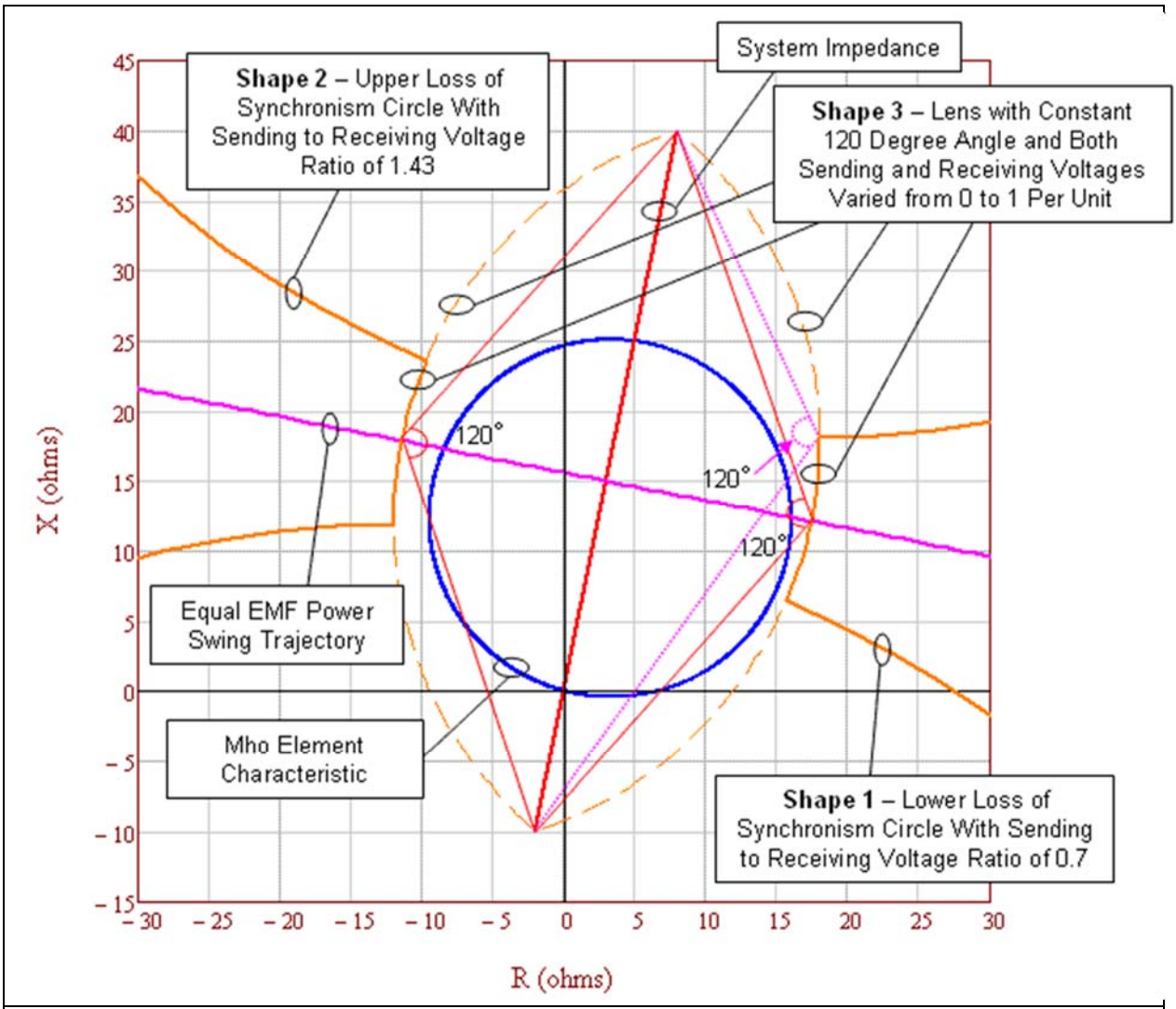


Figure 1: An enlarged graphic illustrating the unstable power swing region formed by the union of three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained 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.

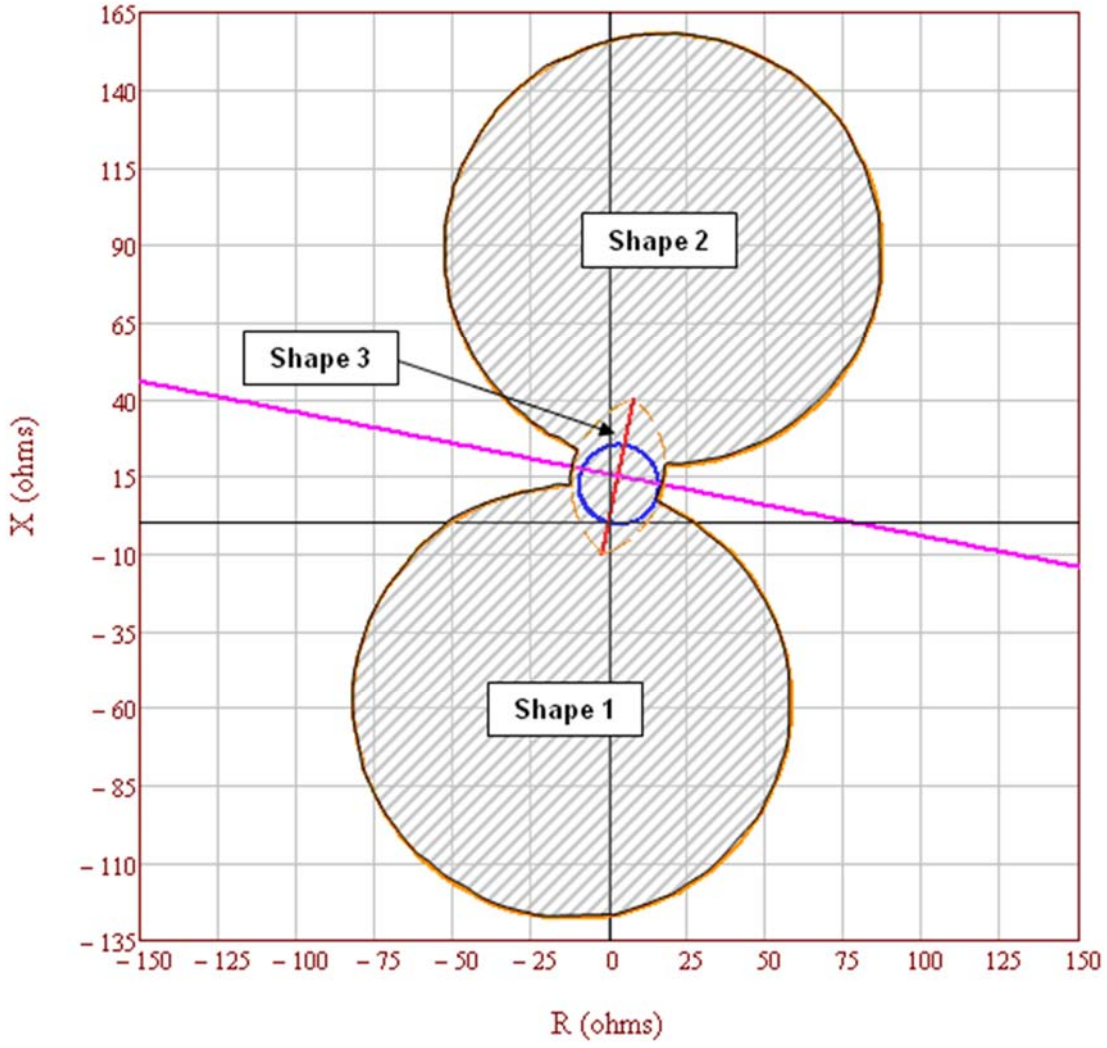


Figure 2: Full graphic of the unstable power swing region formed by the union of the three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region, therefore it meets PRC-26-1 – Attachment B, Criterion A, No.1.

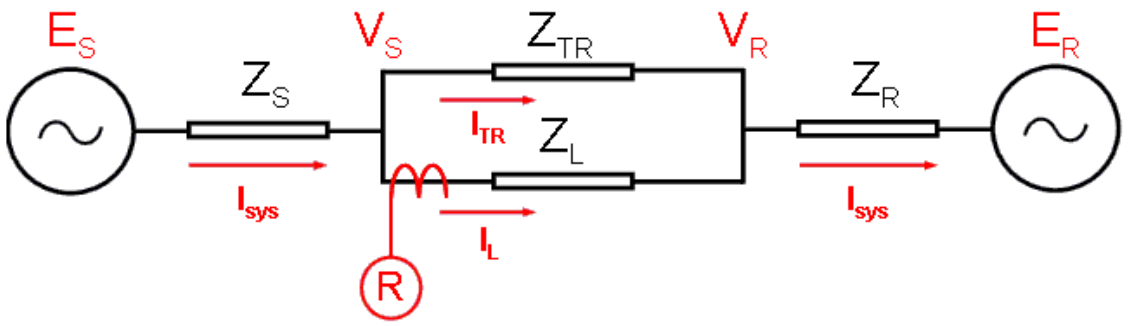


Figure 3: System impedances as seen by Relay R (voltage connections are not shown).

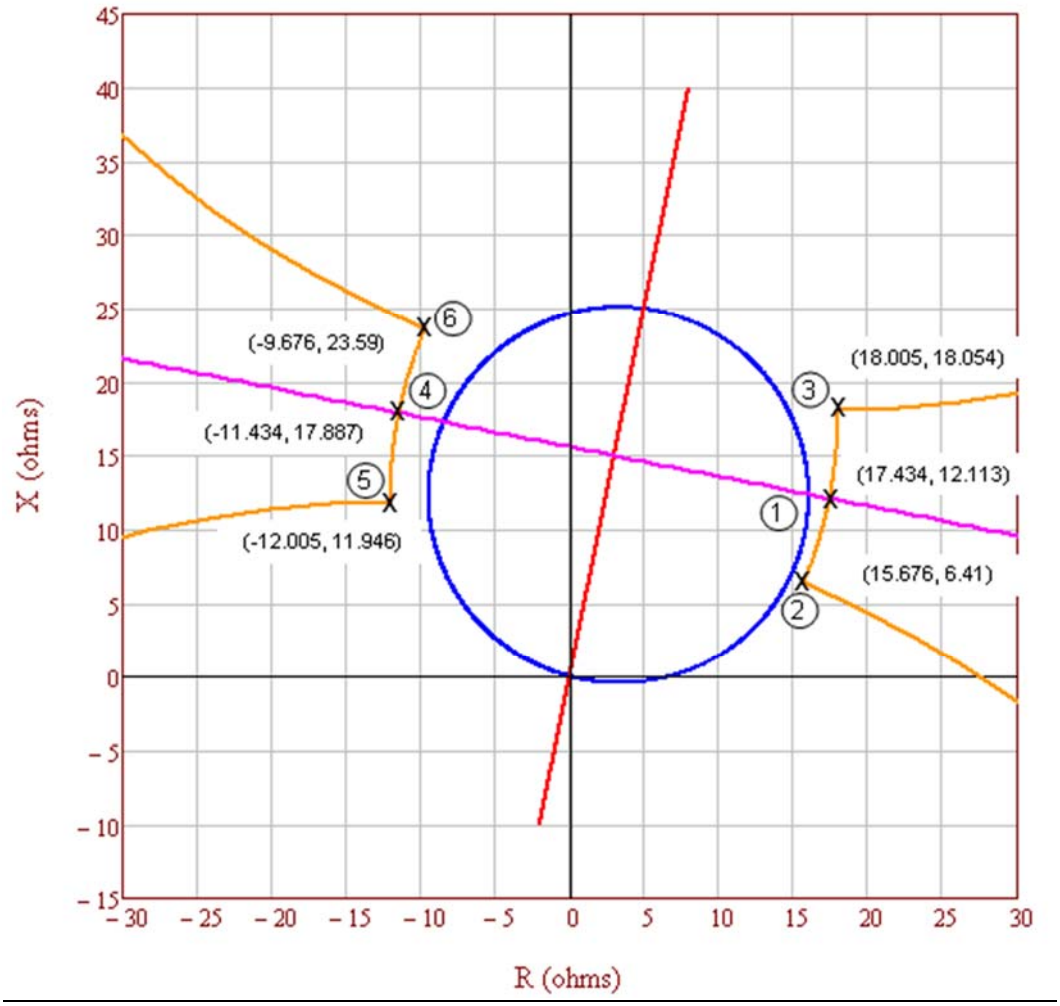


Figure 4: The defining unstable power swing region points where the lens shape intersects the lower and upper loss-of-synchronism circle shapes and where the lens intersects the equal EMF (electromotive force) power swing.

	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)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle -110.6° \, V}{3{,}854\angle 137.1° \, A}$
	$Z_{L-Relay} = -9.676 + j23.59 \, \Omega$

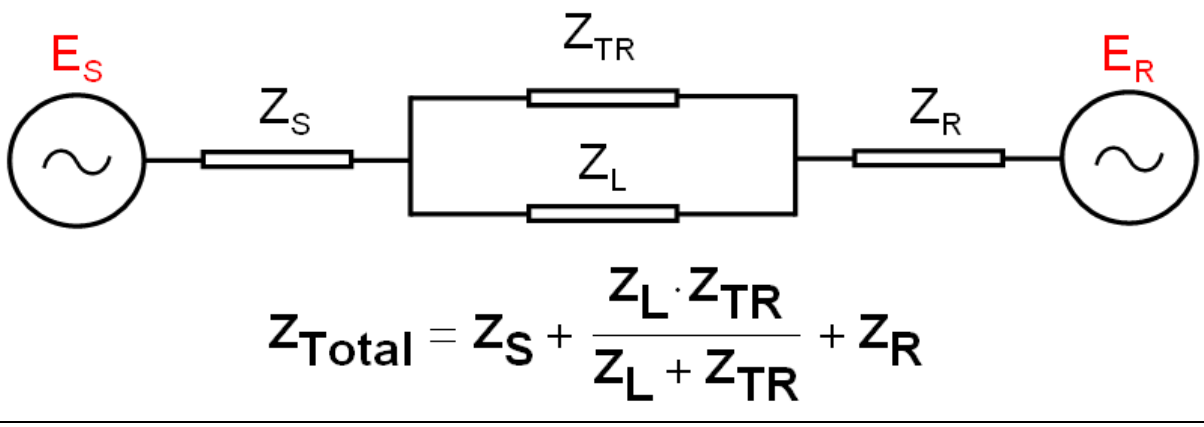


Figure 6: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and parallel transfer impedance Z_{TR}.

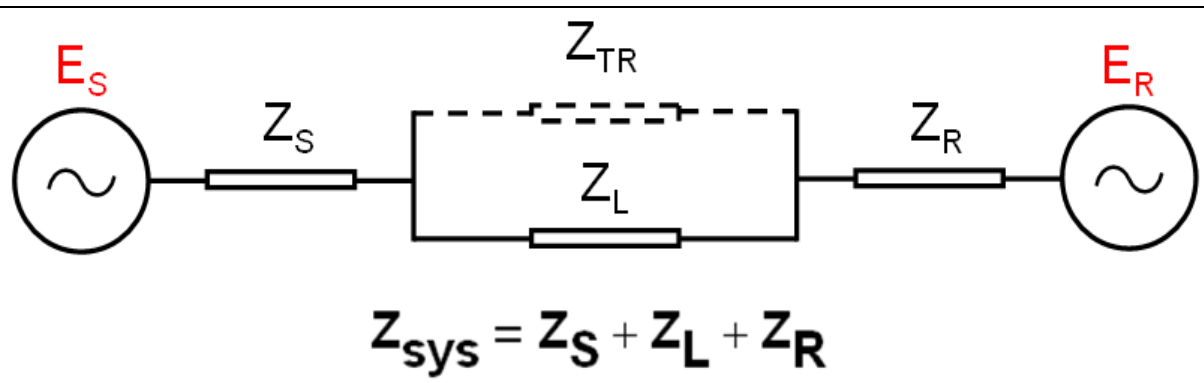


Figure 7: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, and line impedance Z_L with the parallel transfer impedance Z_{TR} removed.

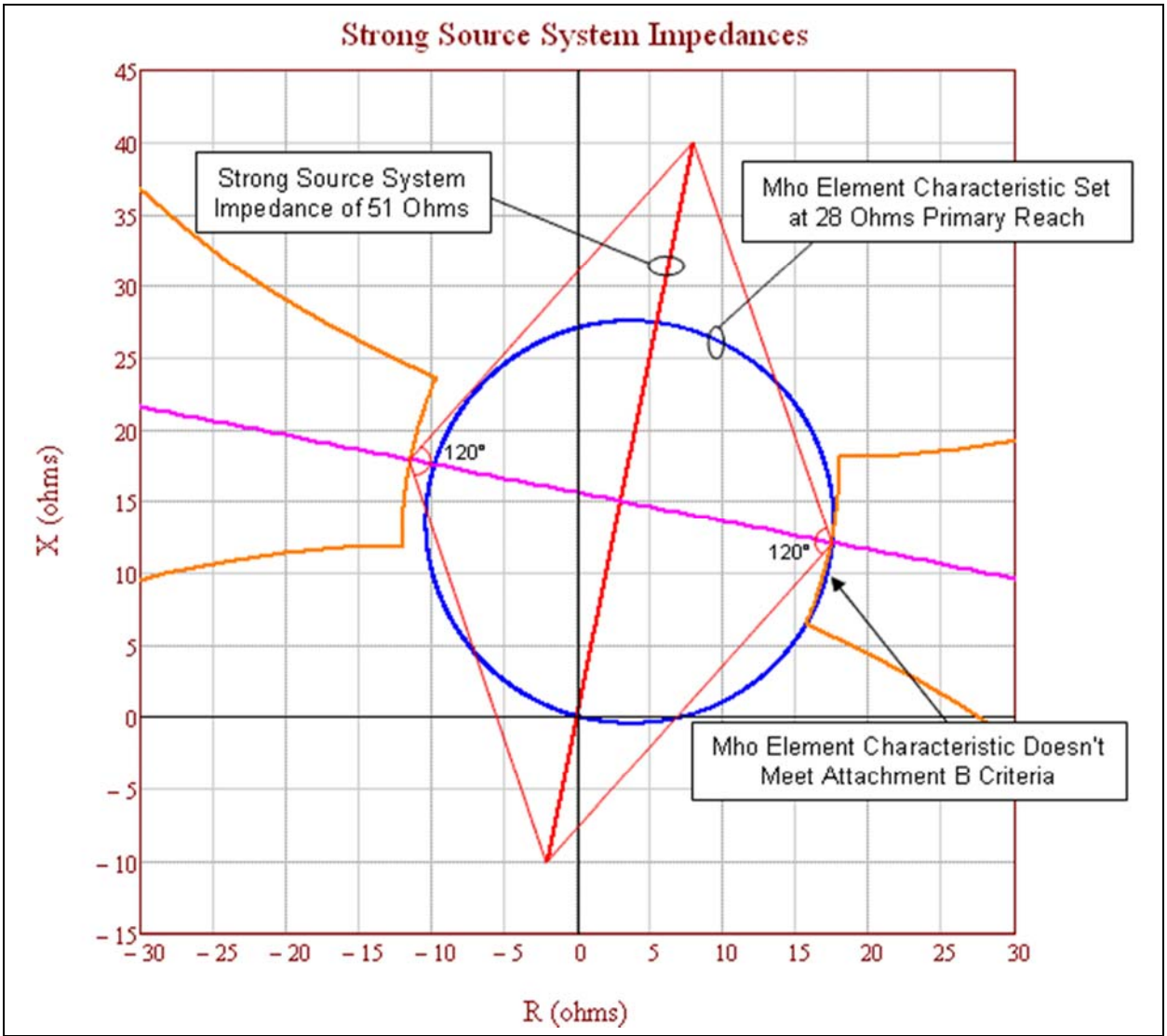


Figure 8: A strong-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) does not meet the PRC-026-1 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region (i.e., 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.

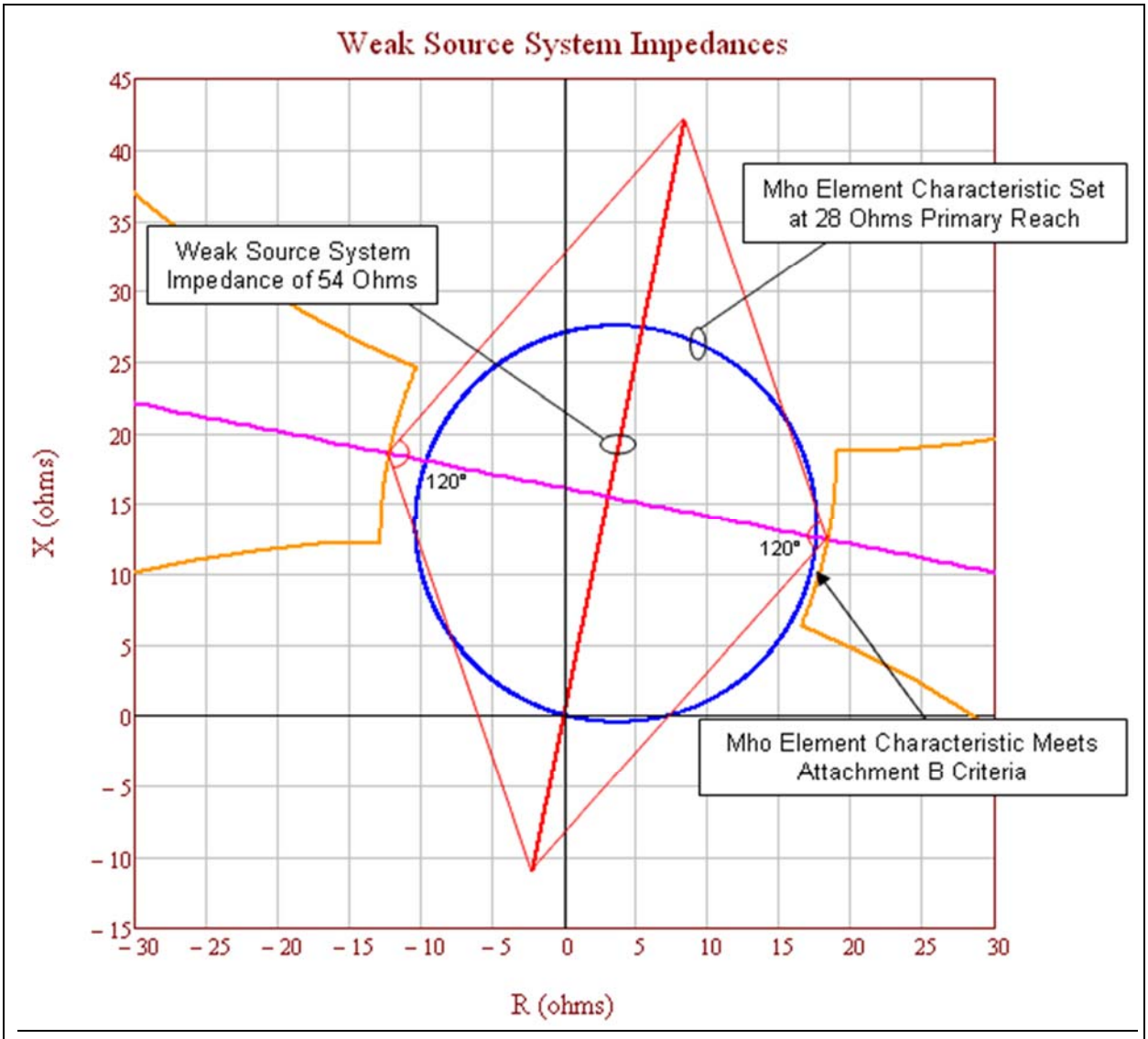


Figure 9: A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) meets the PRC-026-1 – Attachment B, Criterion A because it is completely contained within the unstable power swing region (i.e., the orange characteristic).

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.

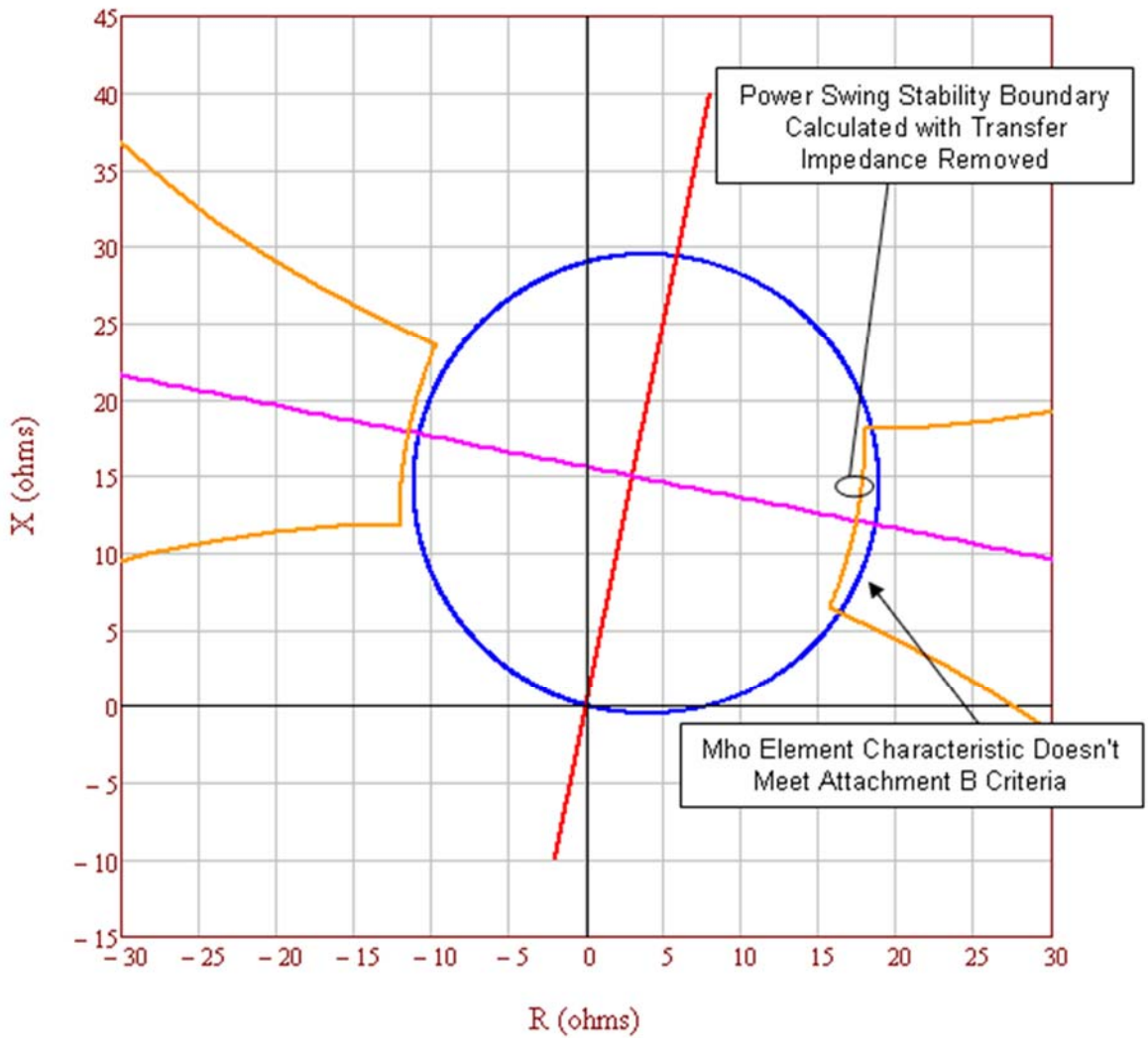


Figure 10: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance removed. This relay mho element characteristic (i.e., the blue circle) does not meet PRC-026-1 – Attachment B, Criterion A because it is not completely contained within 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)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120° \, V - [(2 + j10\ \Omega) \times 4{,}511\angle 71.3° \, A]$
	$V_S = 95{,}757\angle 106.1° \, V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1° \, V}{4{,}511\angle 71.3° \, A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

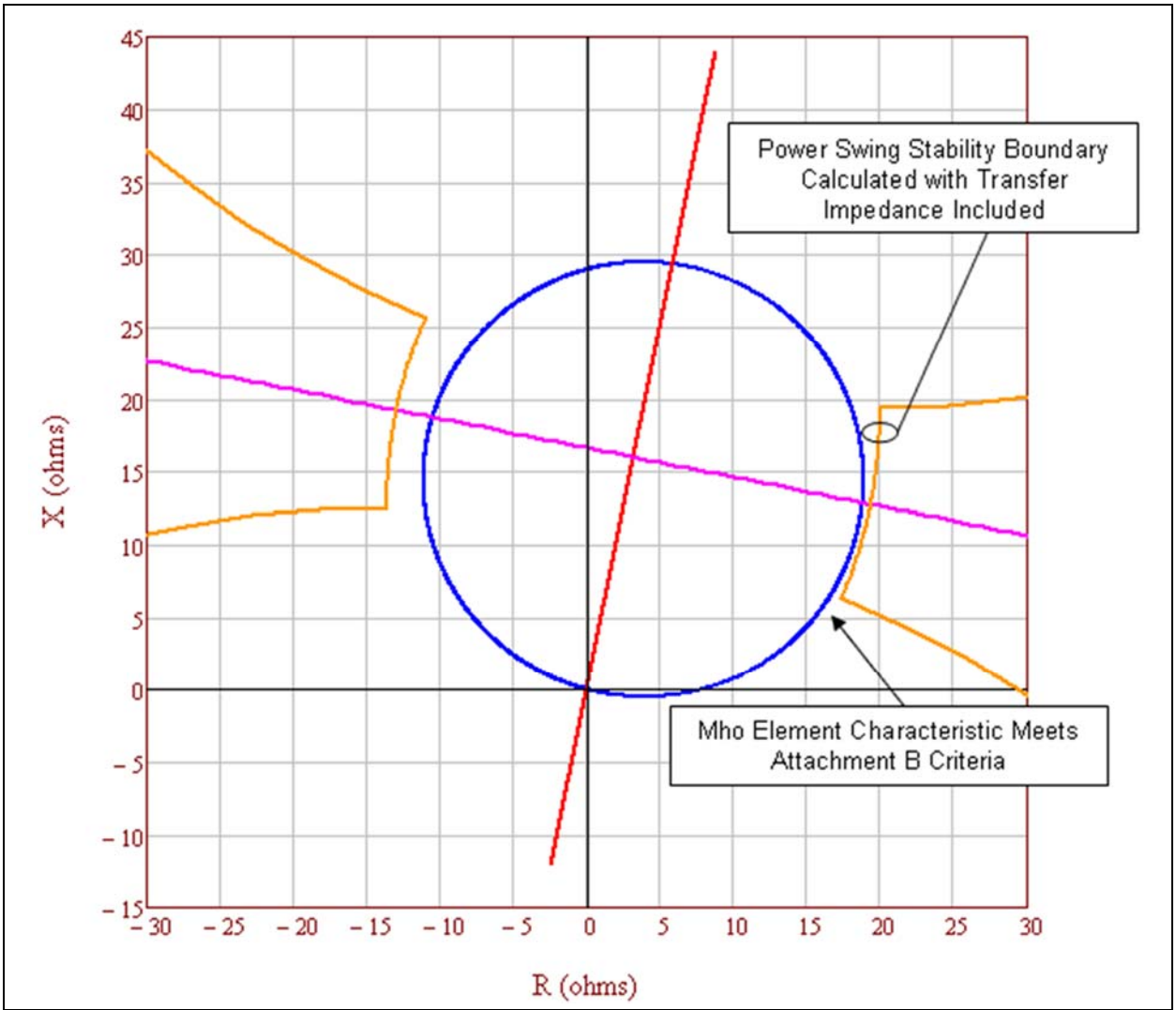


Figure 11: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance included causing the mho element characteristic (i.e., the blue circle) to appear to meet the PRC-026-1 – Attachment B, Criterion A because it is completely contained 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%

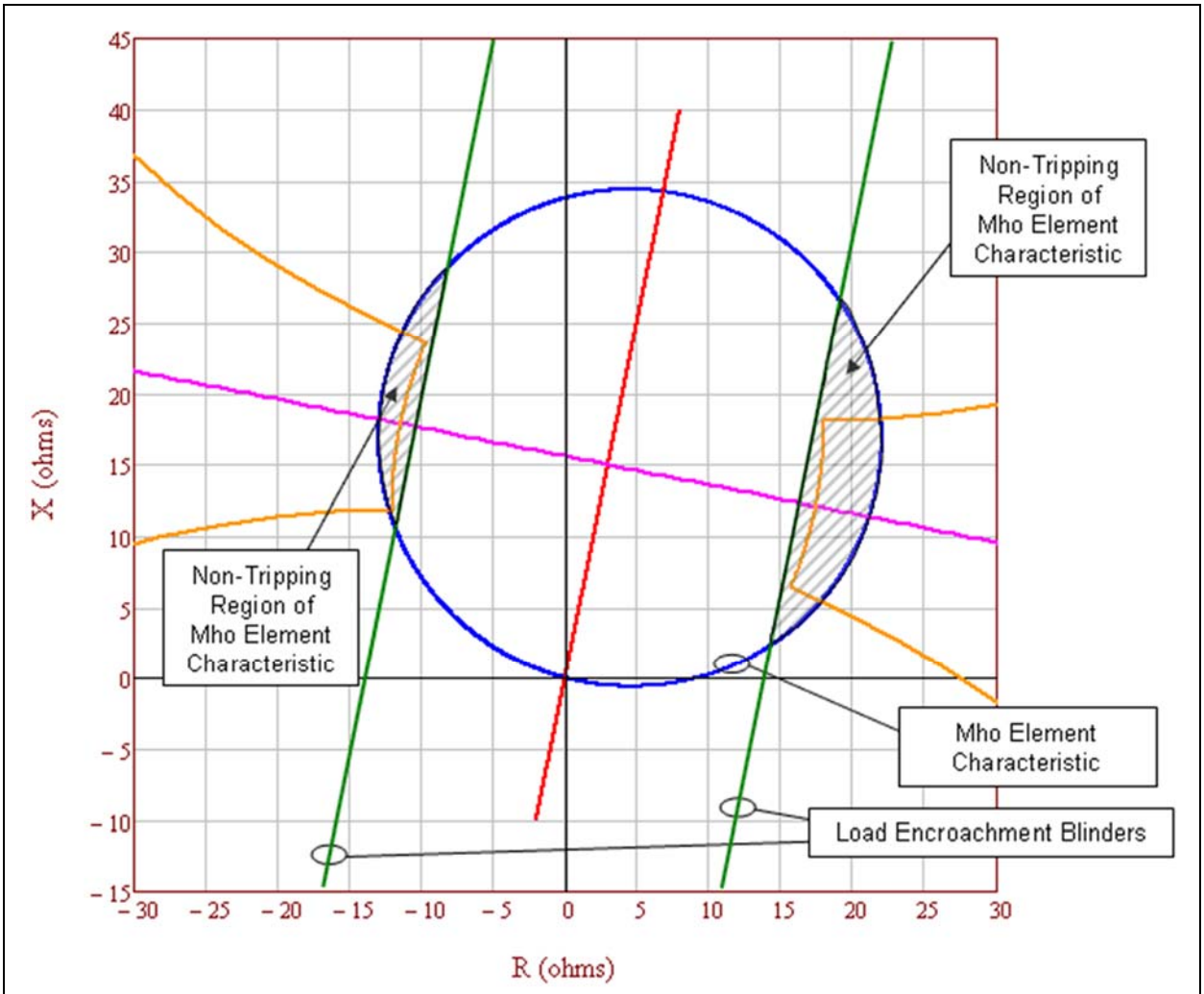


Figure 12: The tripping portion of the mho element characteristic (i.e., the blue circle) not blocked by load encroachment (i.e., the parallel green lines) is completely contained within the unstable power swing region (i.e., the orange characteristic). Therefore, the mho element characteristic meets the PRC-026-1 – Attachment B, Criterion A.

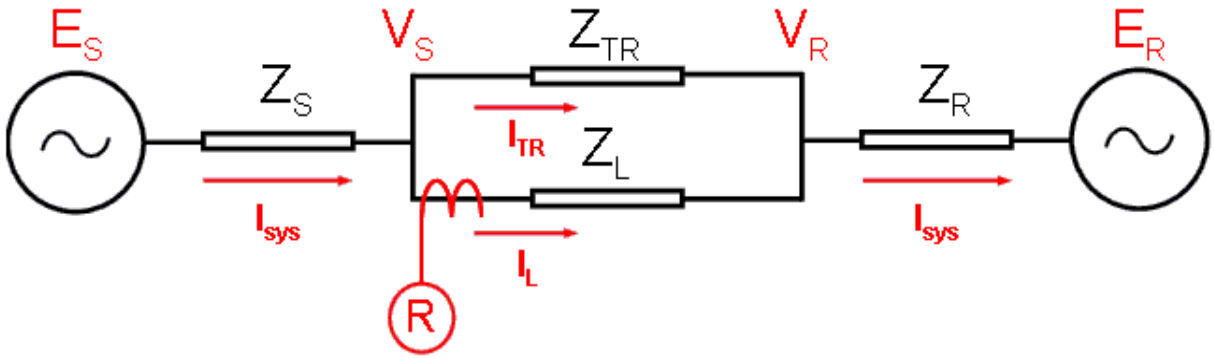


Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

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)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$

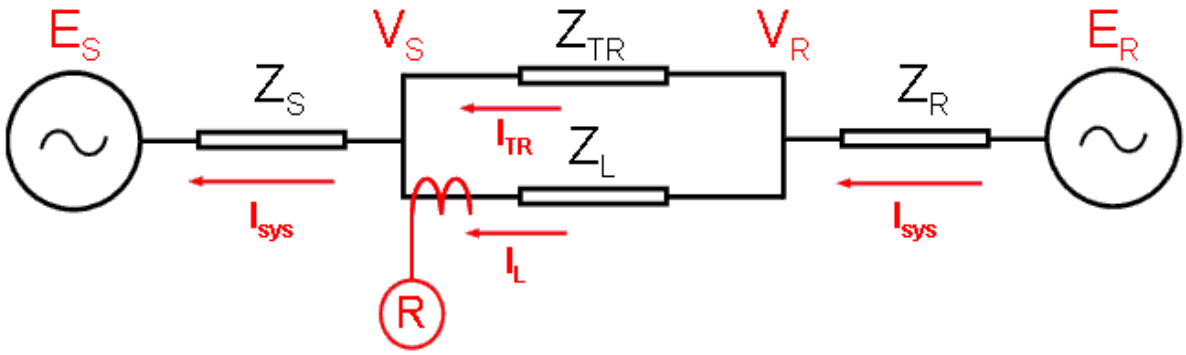


Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

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.

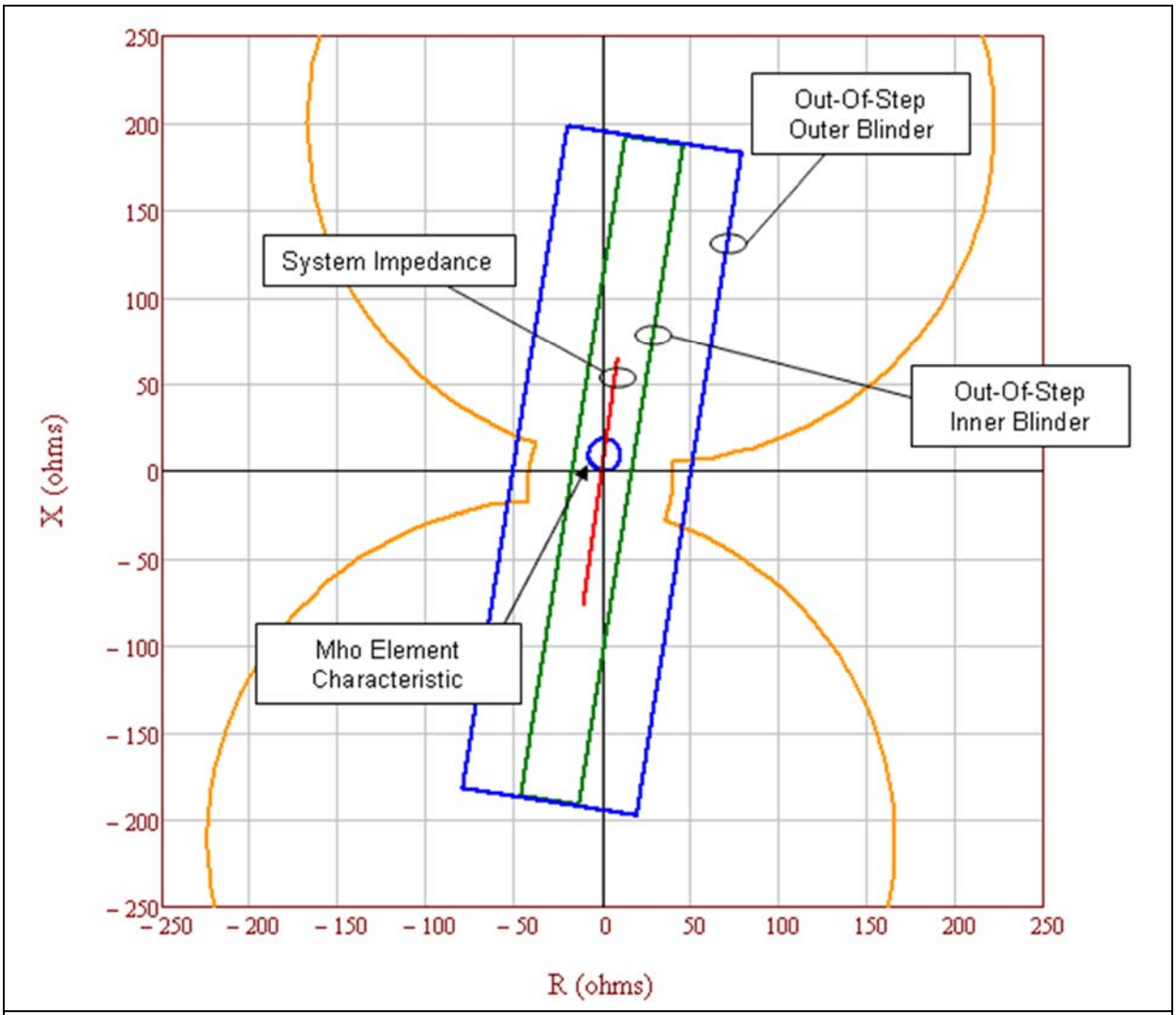


Figure 15: Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-1 – Attachment B, Criterion A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the unstable power swing region (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)	$r_b = \left\lvert \frac{N \times Z_{sys}}{N^2 - 1} \right\rvert$
	$r_b = \left\lvert \frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1} \right\rvert$
	$r_b = 69.987\ \Omega$

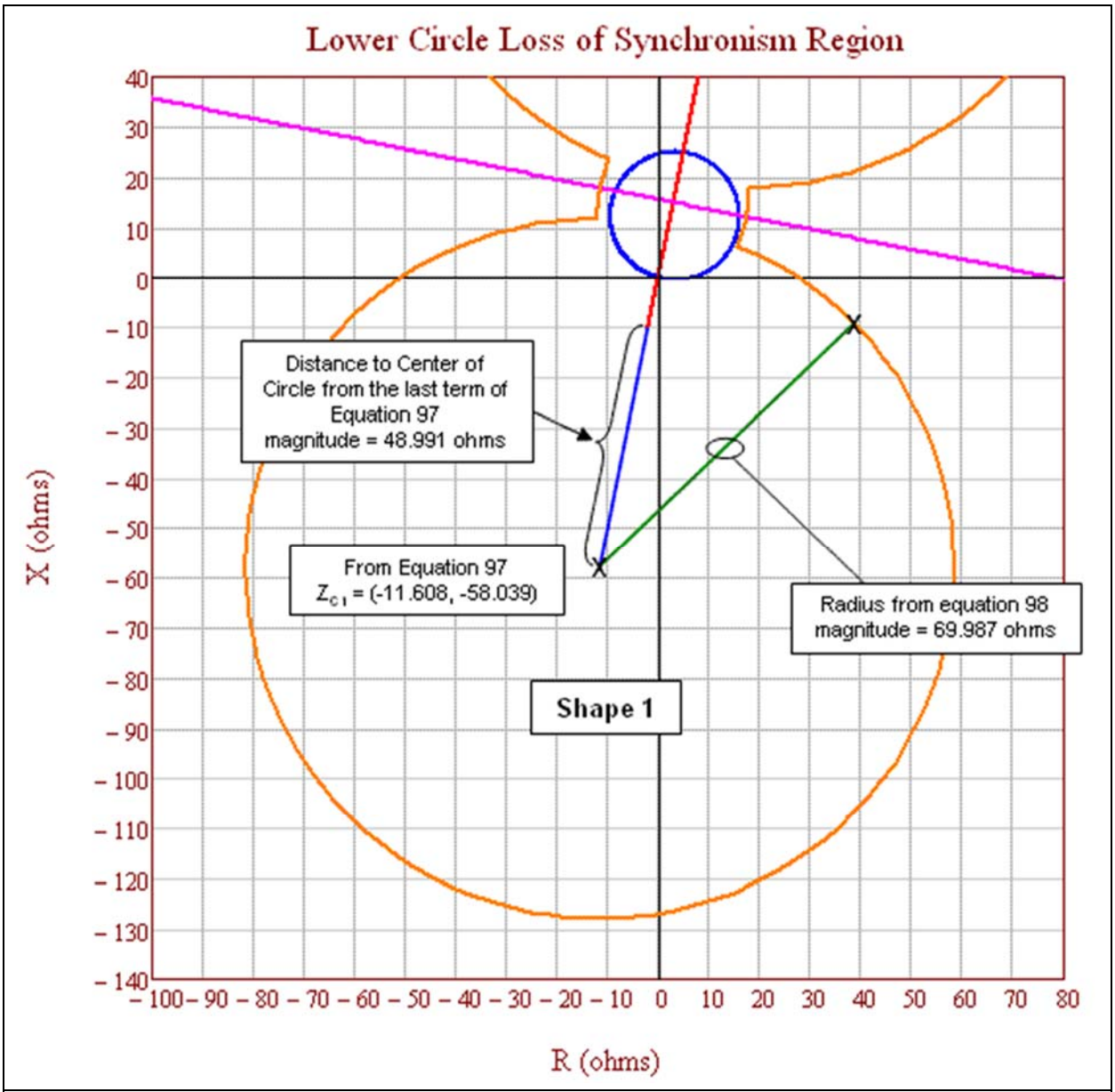


Figure 15a: Lower circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

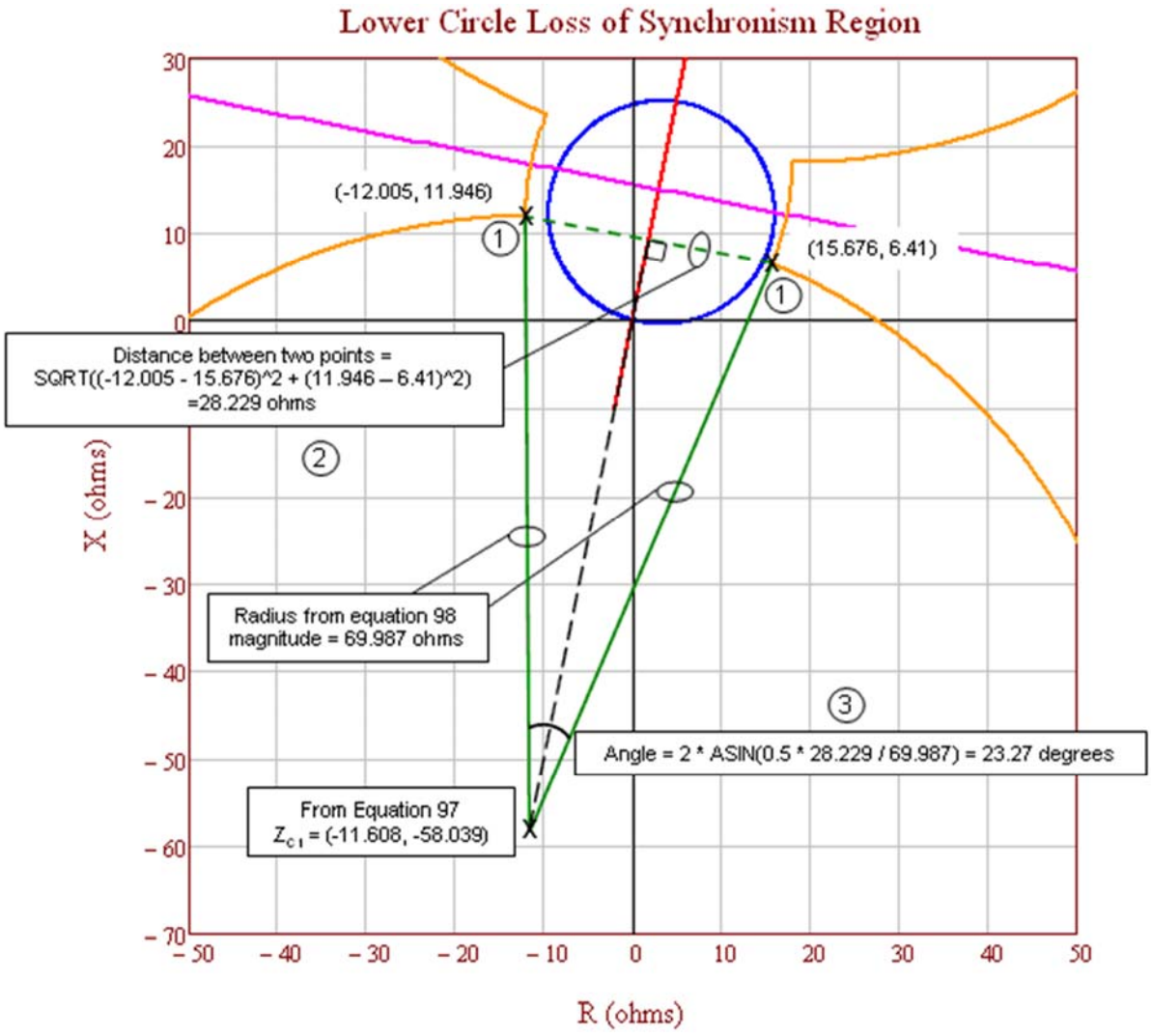


Figure 15b: Lower circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the lower circle loss-of-synchronism points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 0.7 (see lens shape 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.

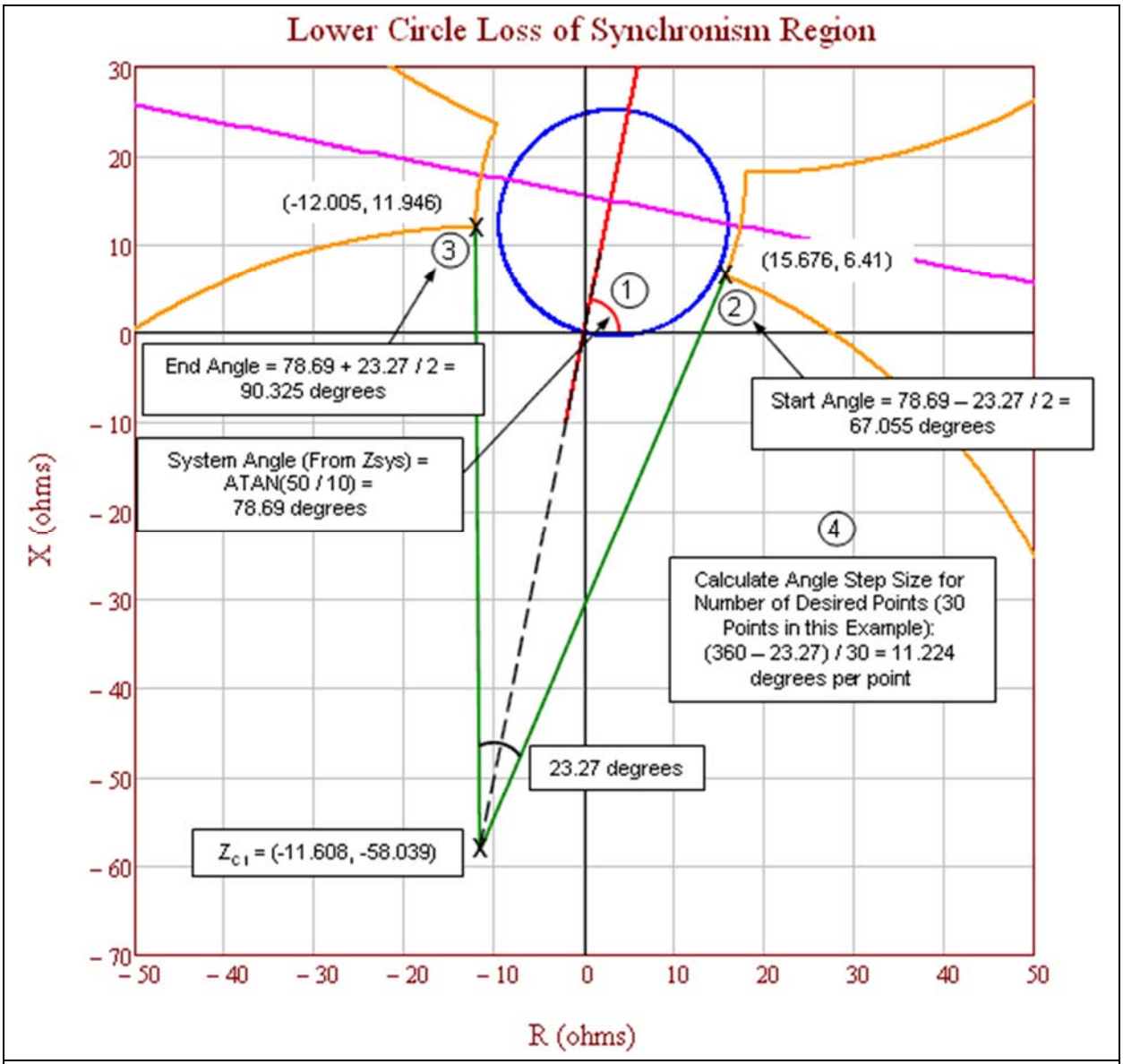


Figure 15c: Lower circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

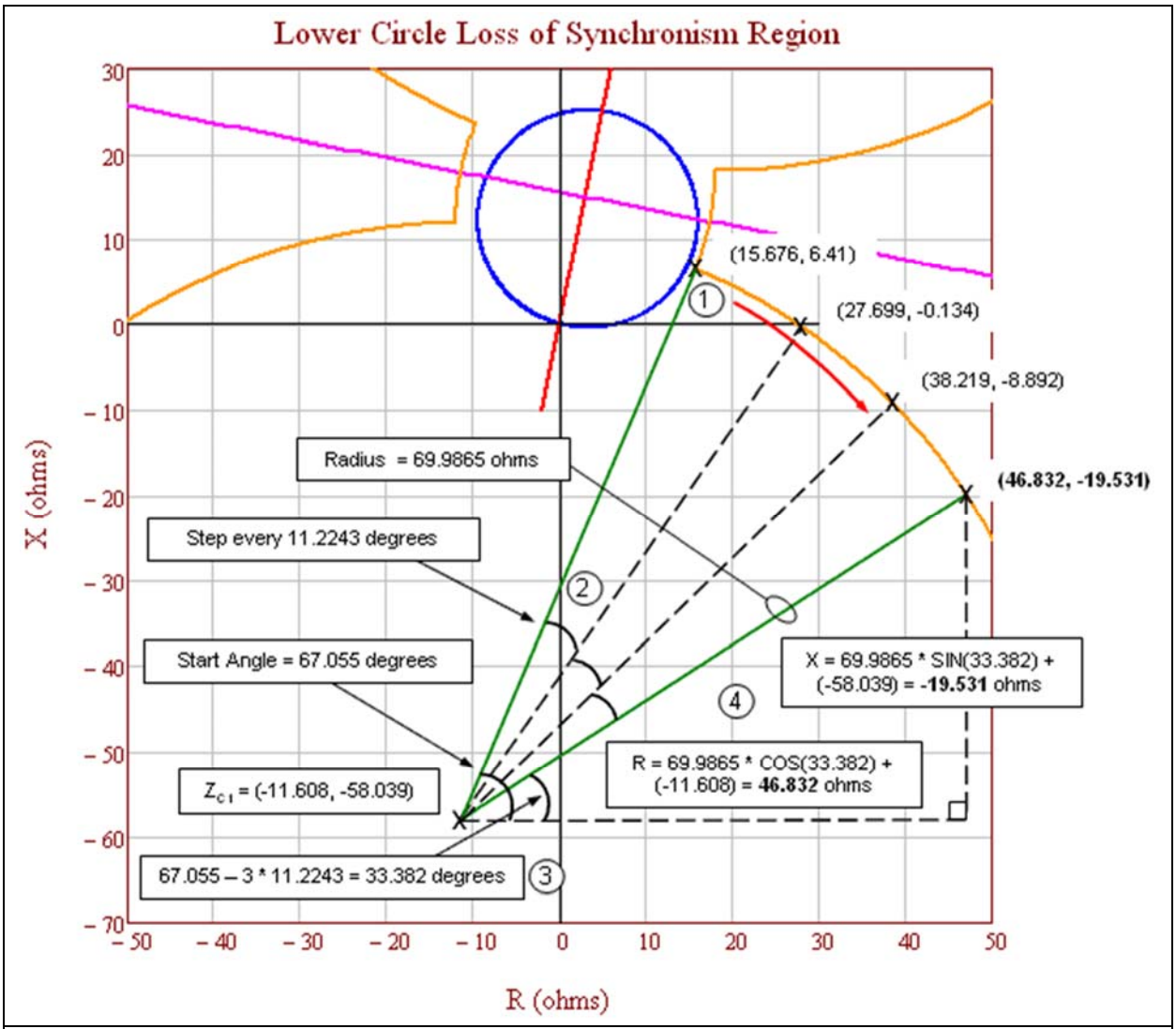


Figure 15d: Lower circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R–X coordinates.

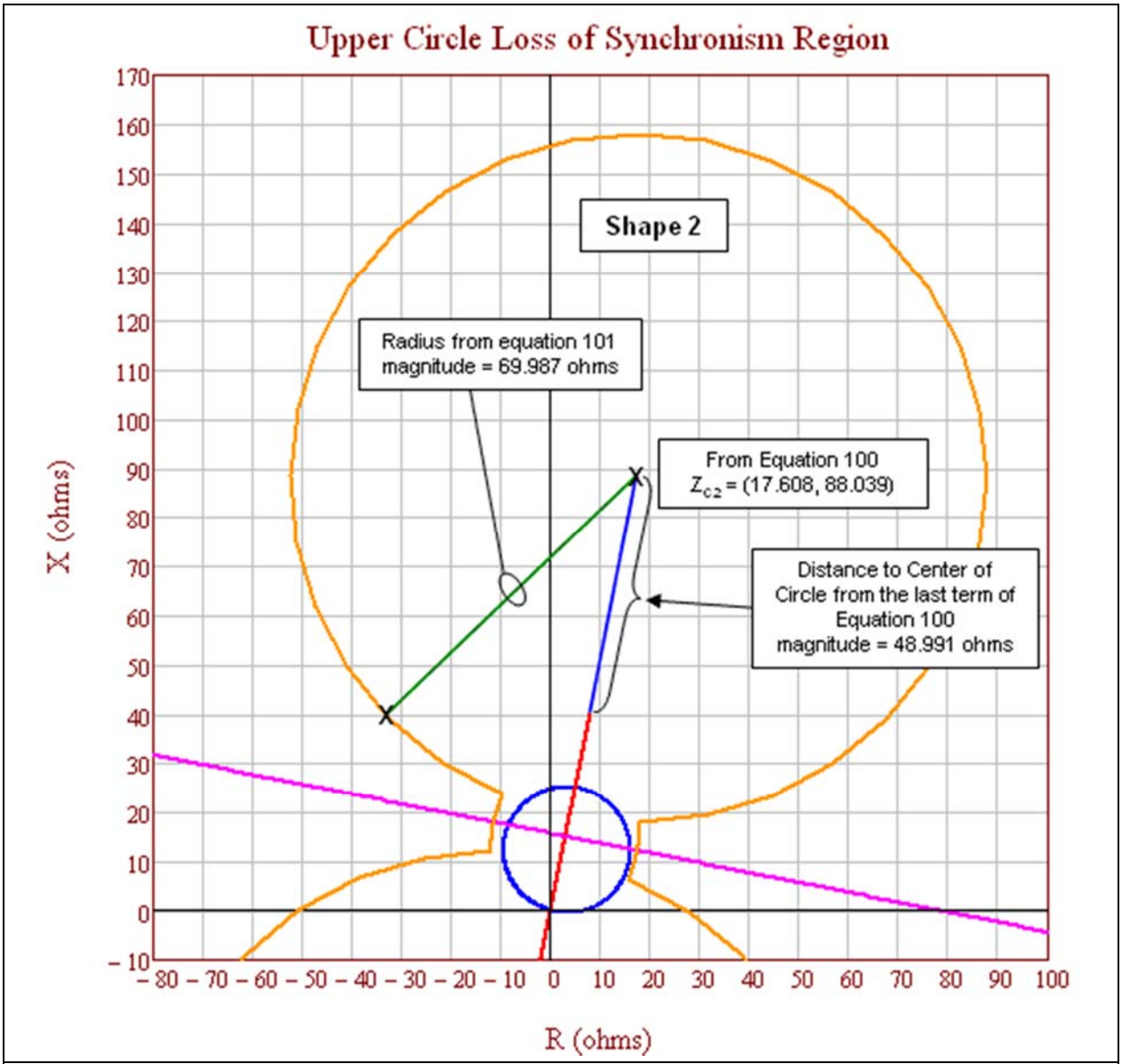


Figure 15e: Upper circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

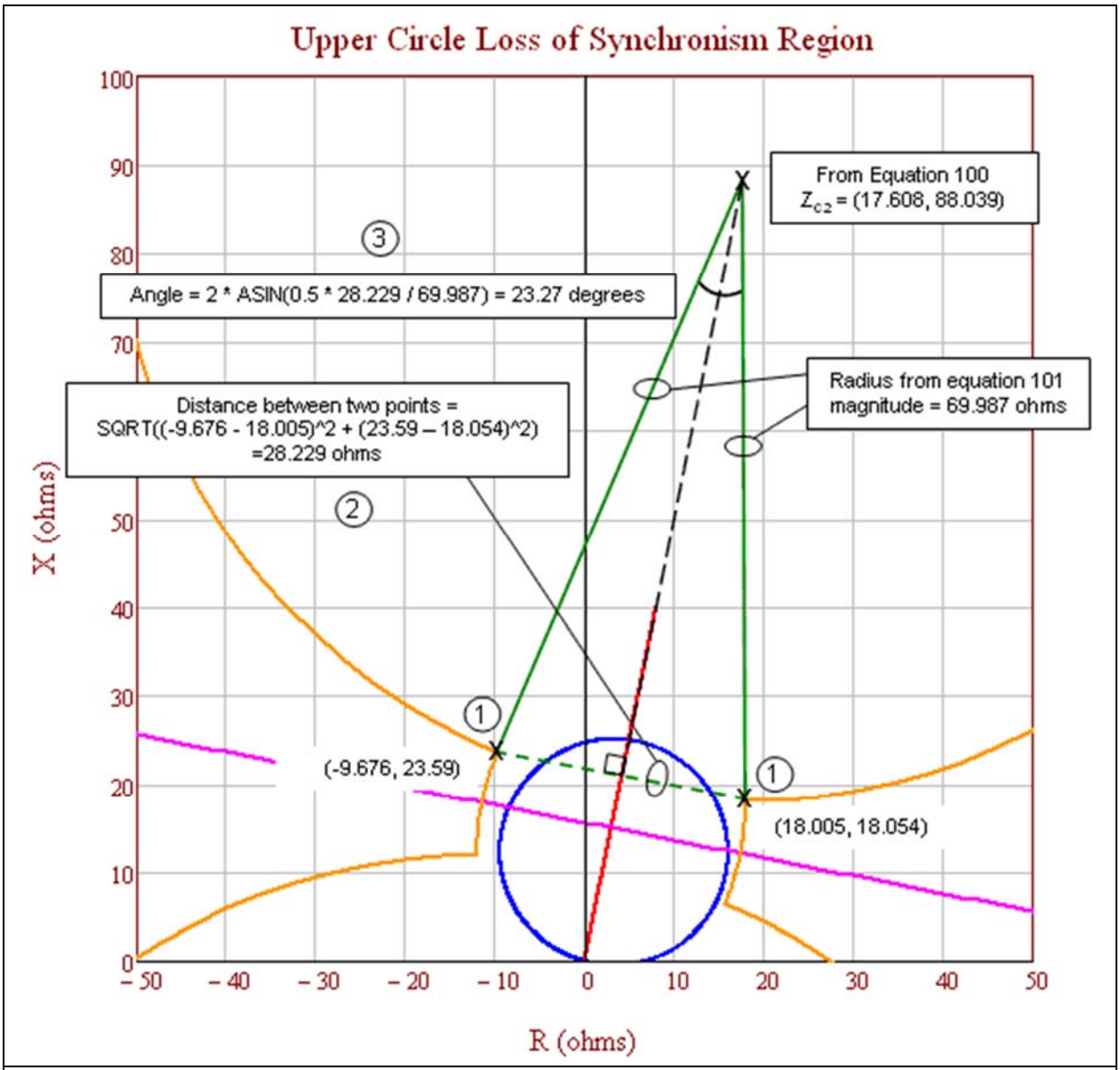


Figure 15f: Upper circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the upper circle points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 1.43 (see lens shape calculations in Tables 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.

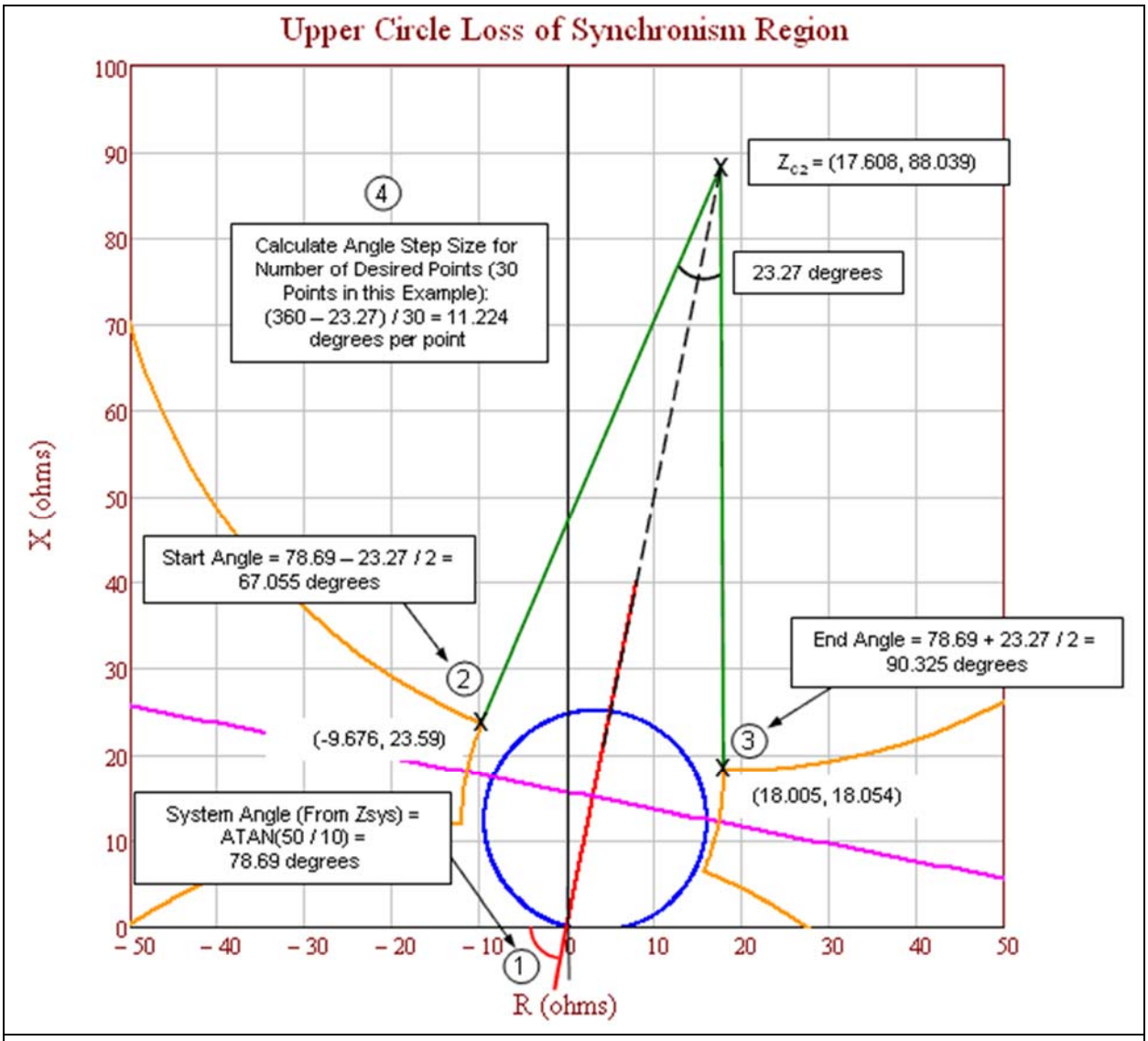


Figure 15g: Upper circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

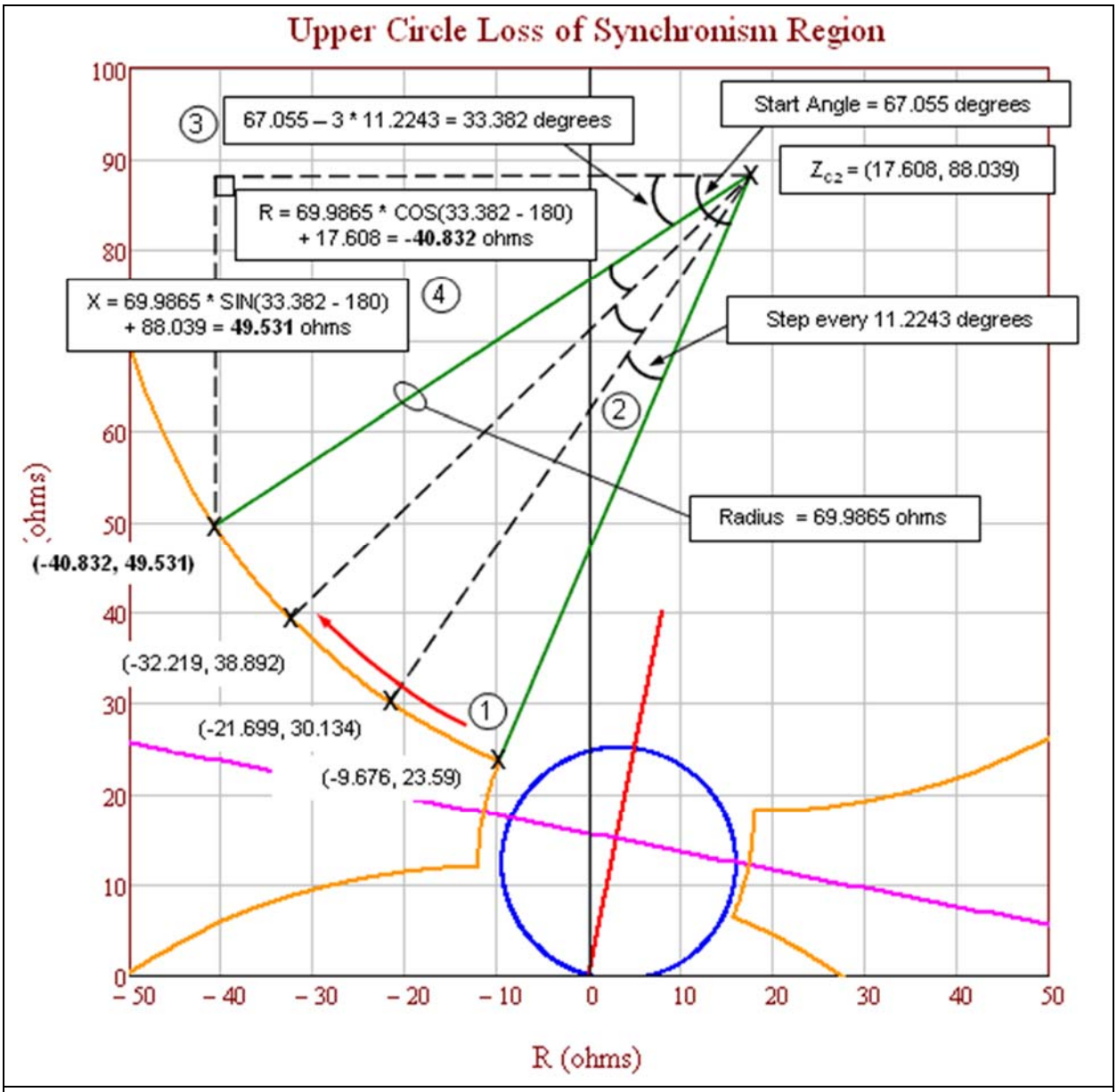


Figure 15h: Upper circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step 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).

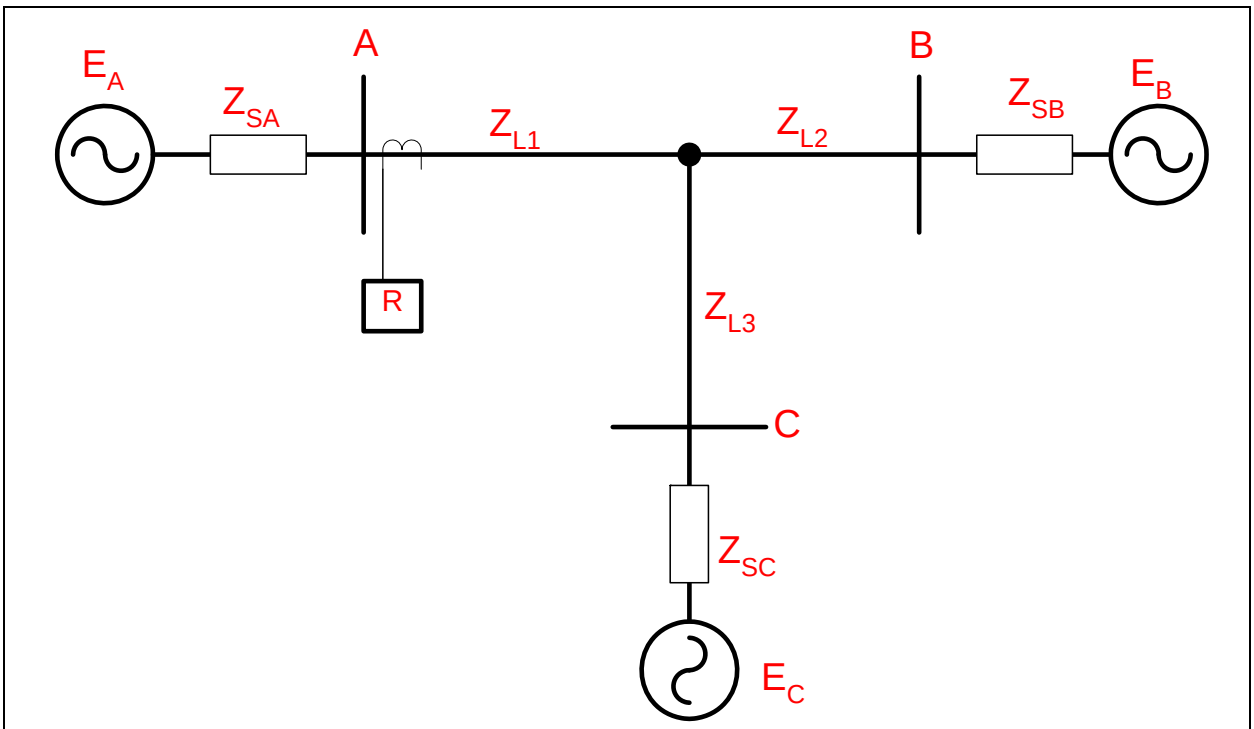


Figure 15j: Three-terminal line. To evaluate the load-responsive protective relays on the three-terminal line at Terminal A, the circuit in Figure 15j is first reduced to the equivalent circuit shown in Figure 15k. The evaluation process for the load-responsive protective relays on the line at Terminal A will now be the same as that of the two-terminal line.

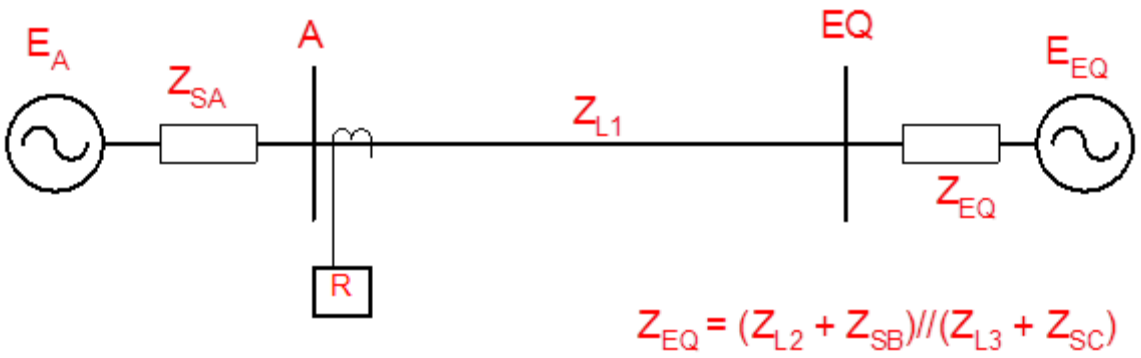


Figure 15k: Three-terminal line reduced to a two-terminal line.

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.

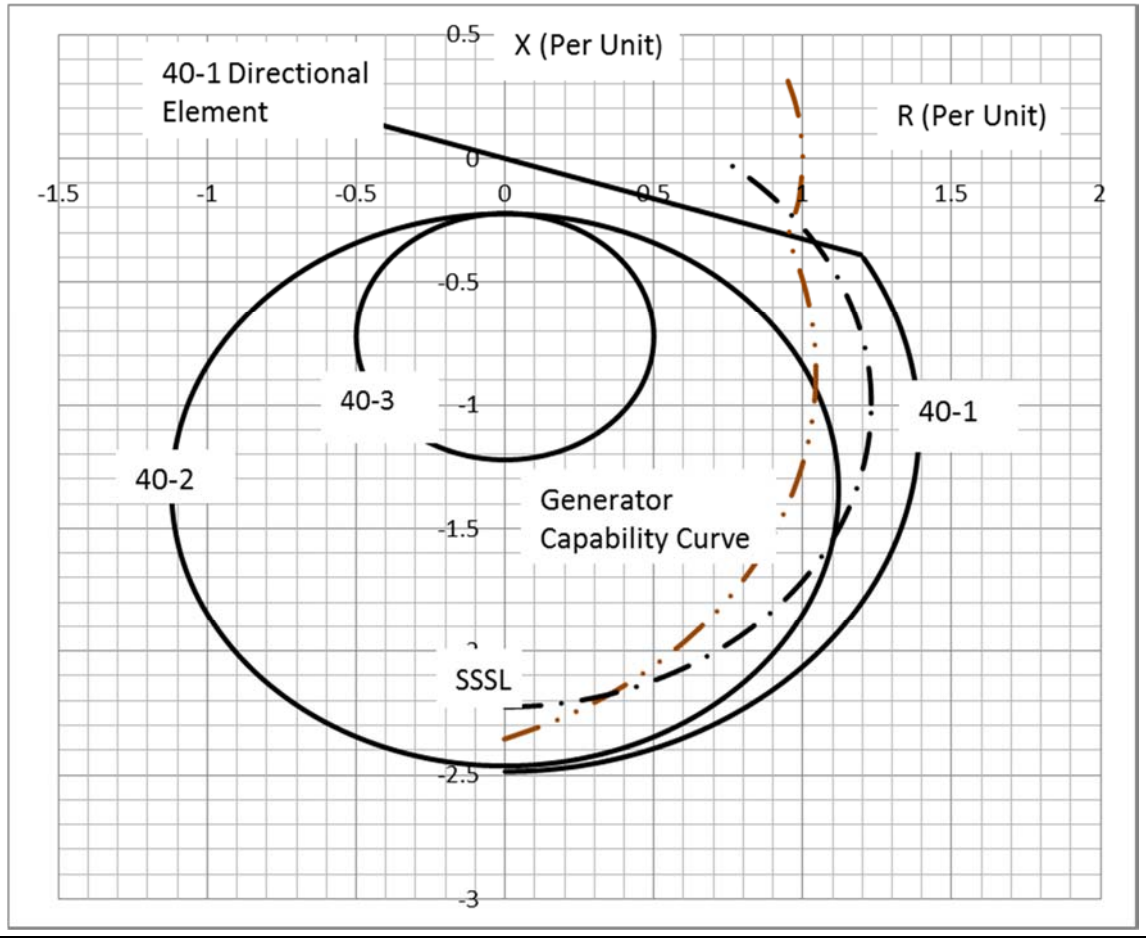


Figure 16: An R-X graph of typical impedance settings for loss-of-field relays.

[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.

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[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.

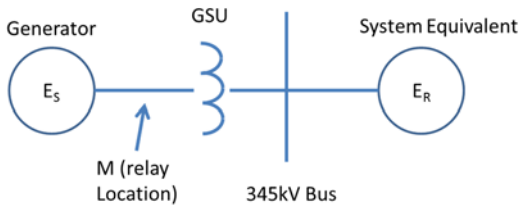


Figure 17: Simple one-line diagram of the system to be evaluated.

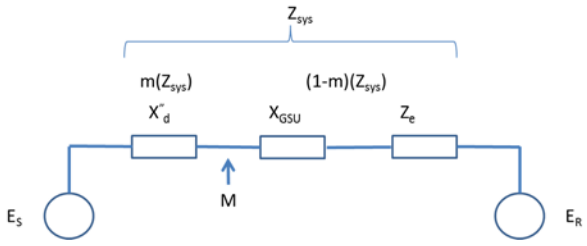


Figure 18: Simple system equivalent impedance diagram to be evaluated.[29]

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.

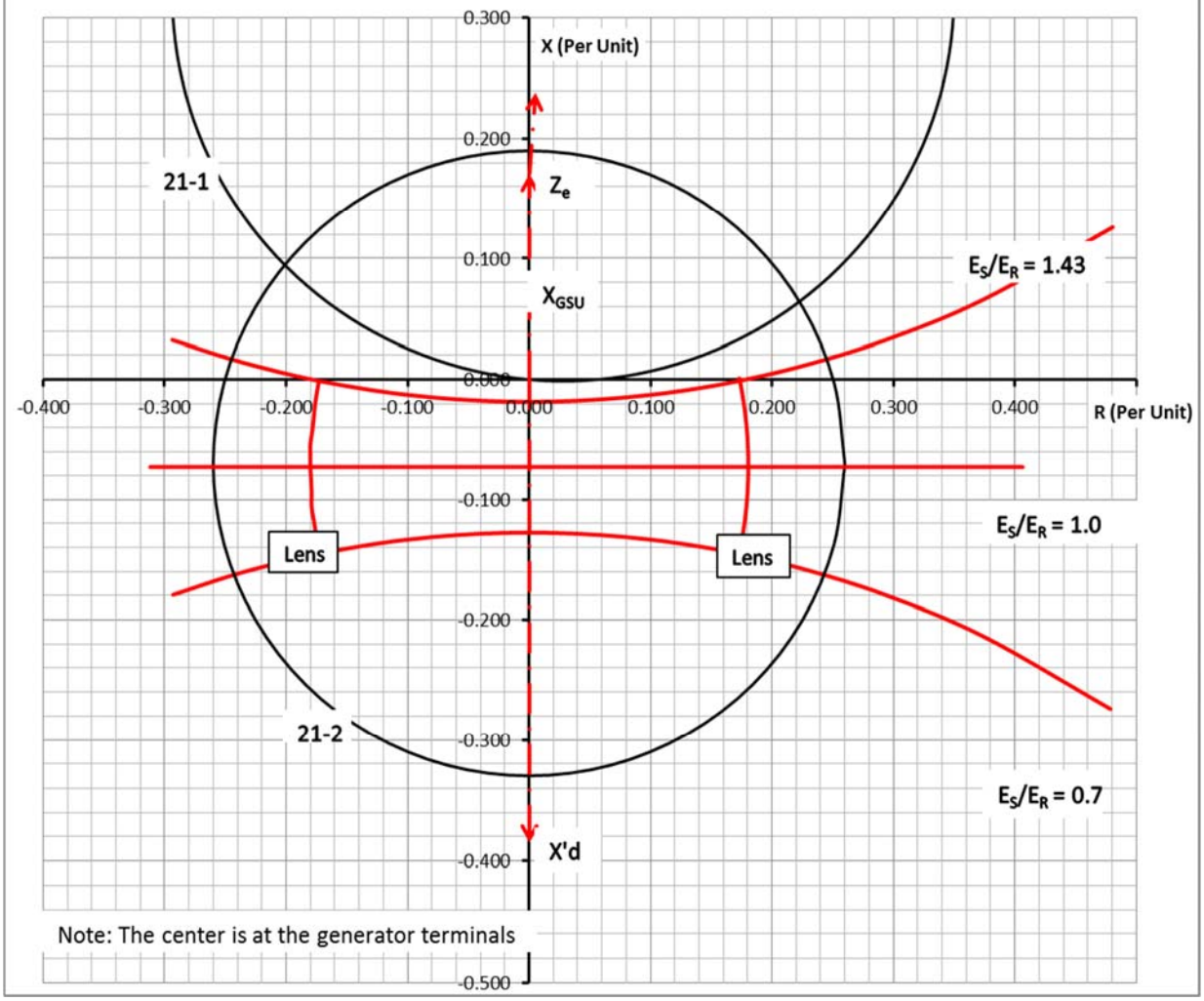


Figure 19: Swing impedance graph for impedance relays at a generating facility.

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.

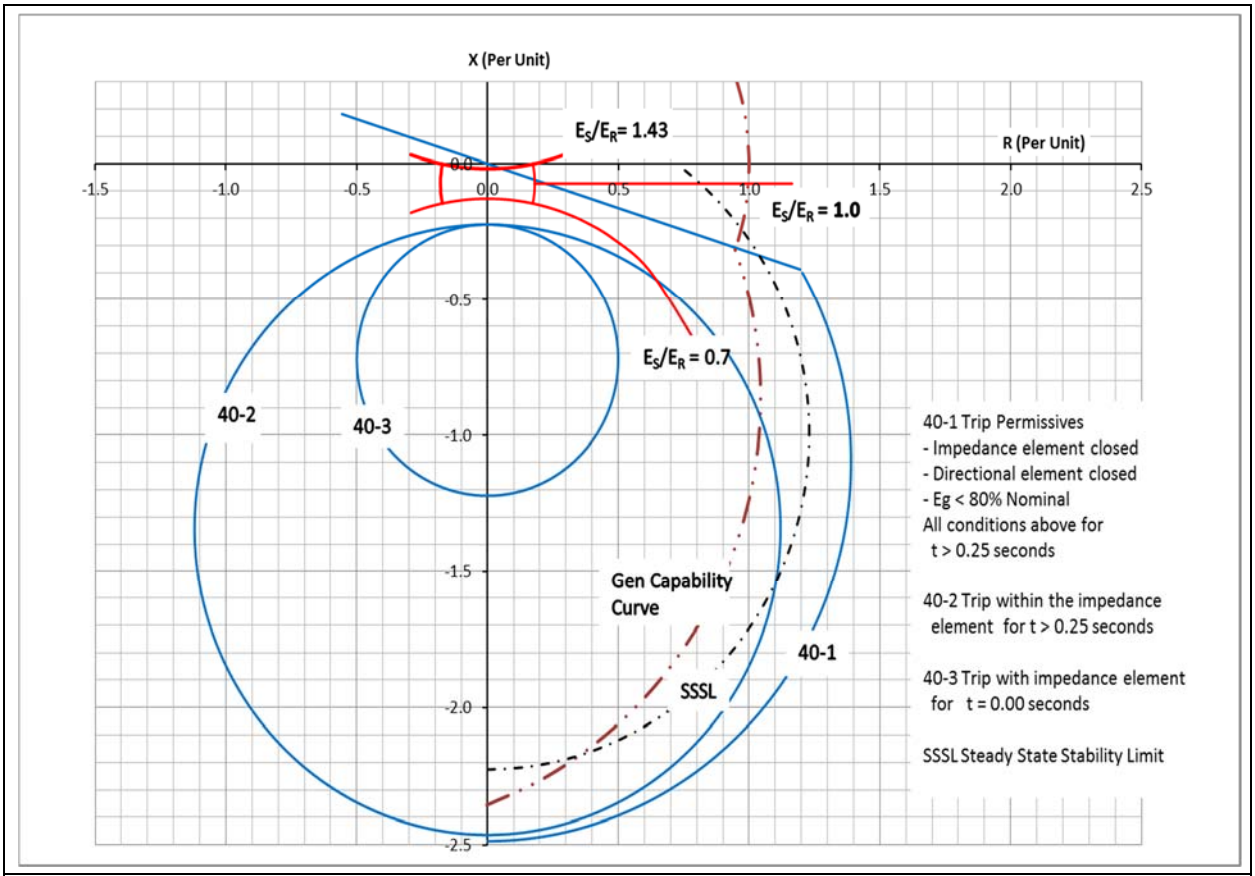


Figure 20: Typical R-X graph for loss-of-field relays with a portion of the unstable power swing region defined by PRC-026-1 – Attachment B, Criterion A.

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.

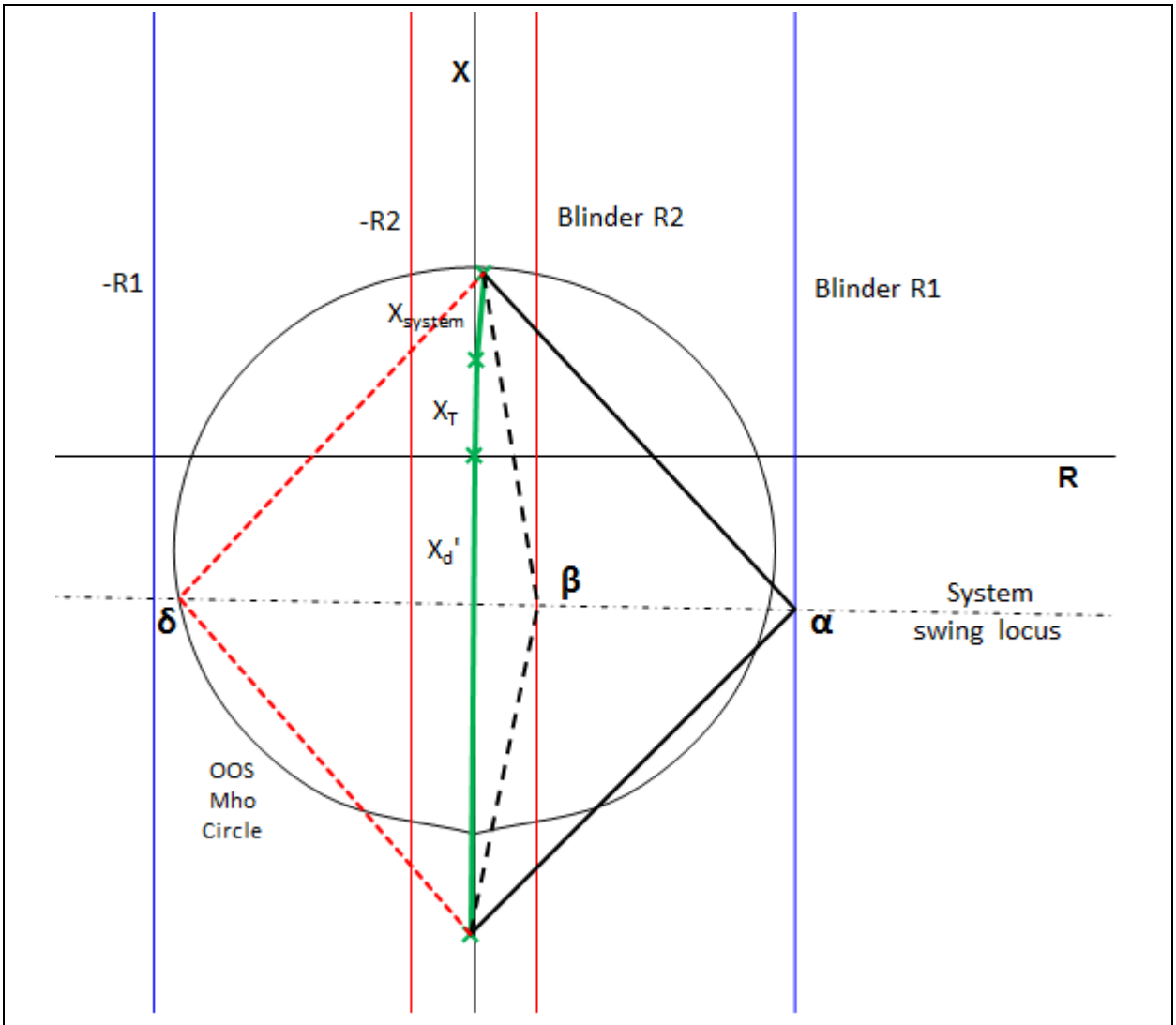


Figure 21: Double Blinder Scheme generic out of step characteristics.

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.

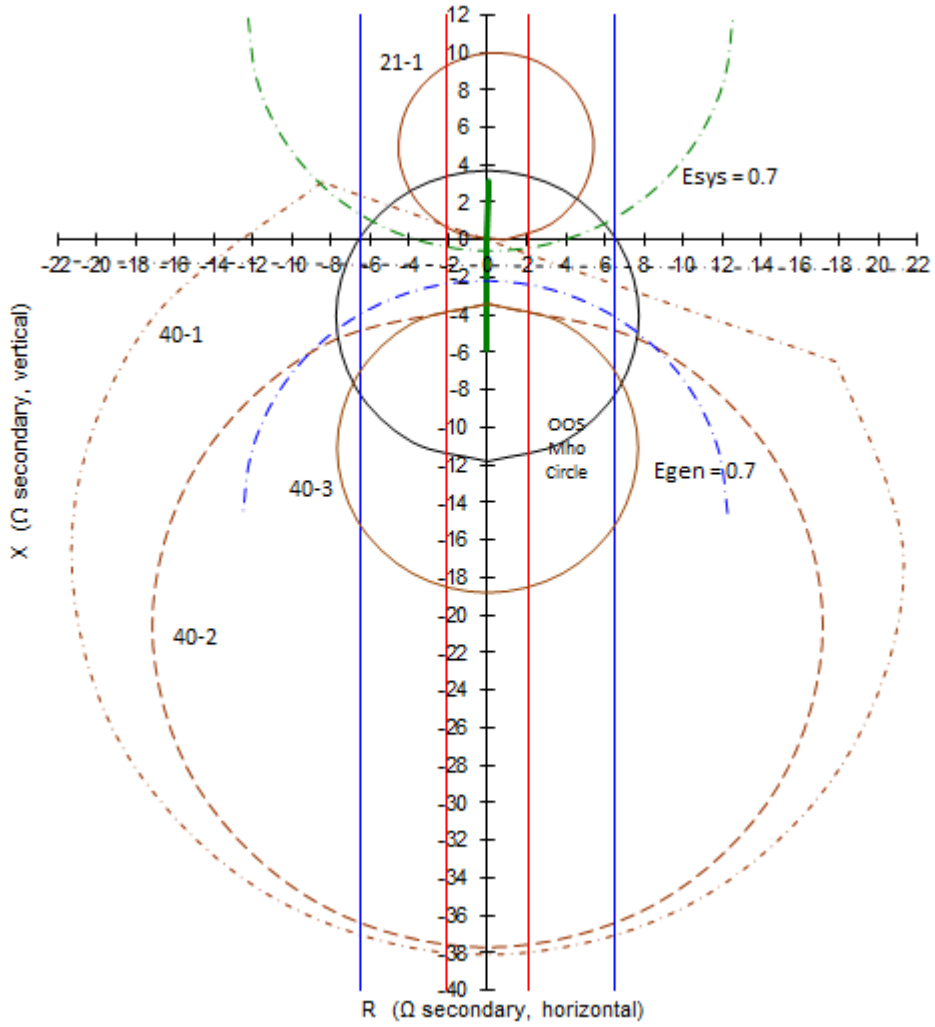


Figure 22: Double Blinder Out-of-Step Scheme with unit impedance data and load-responsive protective relay impedance characteristics for the example 940 MVA generator, scaled in relay secondary ohms.

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.

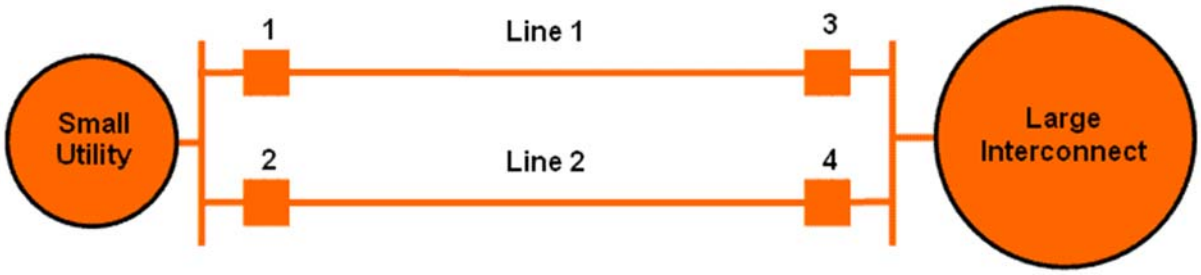


Figure 23: A simple electrical system where two lines tie a small utility to a much larger interconnection.

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.

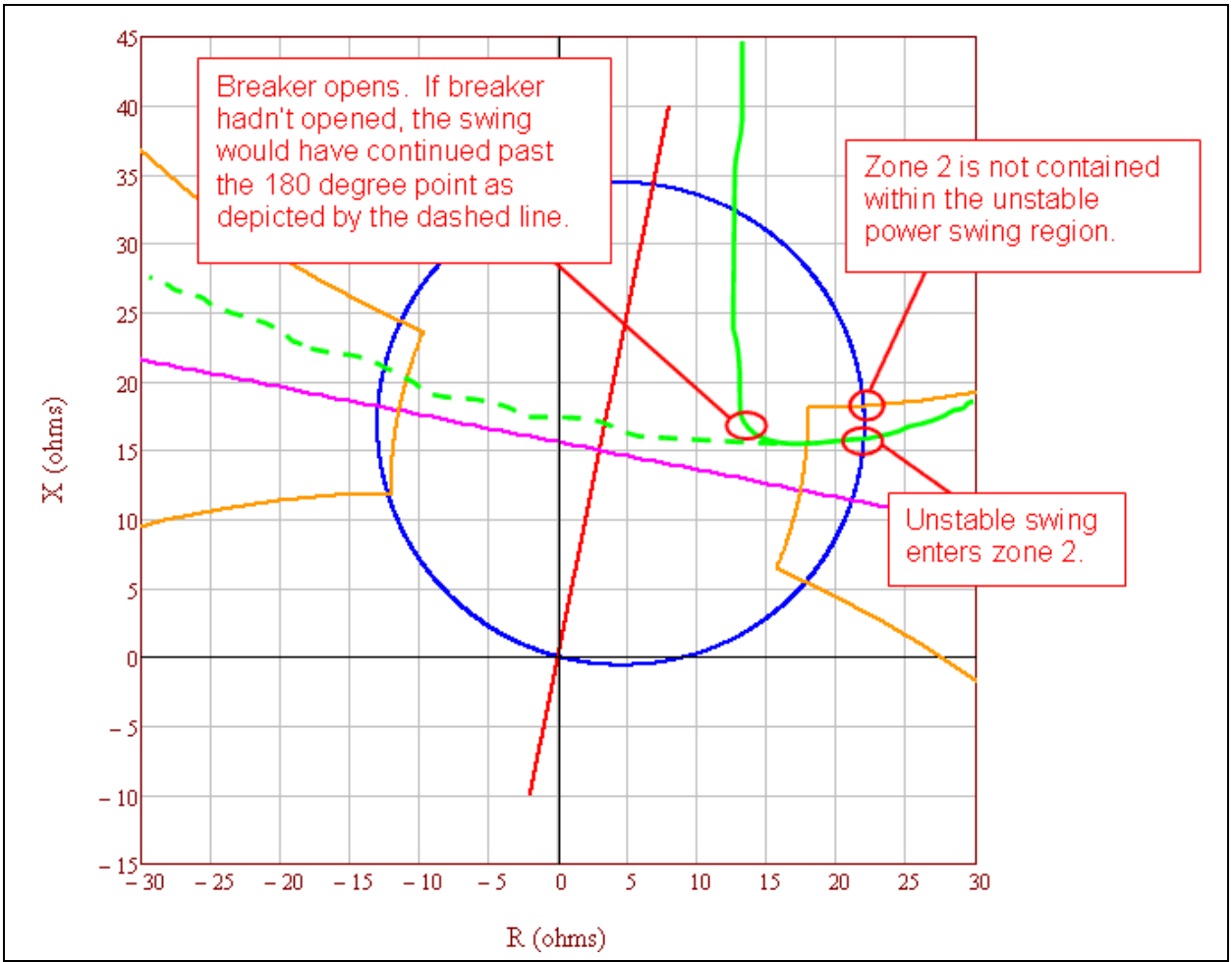


Figure 24: In this case, the Zone 2 element on circuit breakers 1, 2, 3, and 4 did not meet the PRC-026-1 – Attachment B criteria (this figure depicts the power swing as seen by relays on breakers 3 and 4).

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.

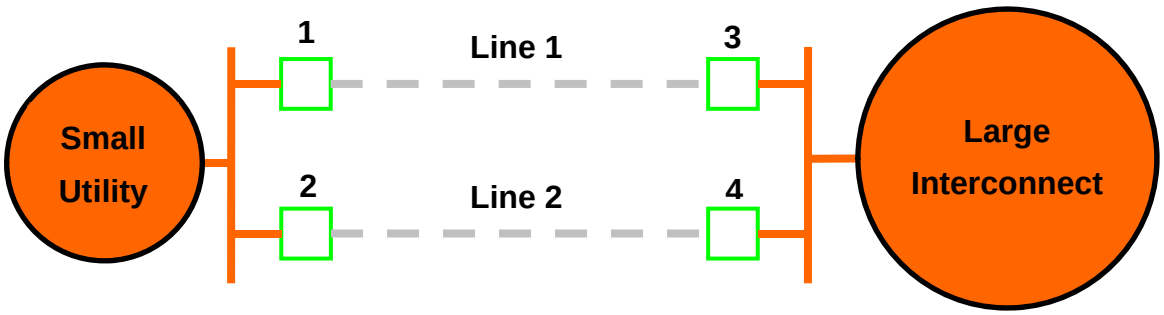


Figure 25: Islanding of the small utility due to Lines 1 and 2 tripping in response to an unstable power swing.

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.

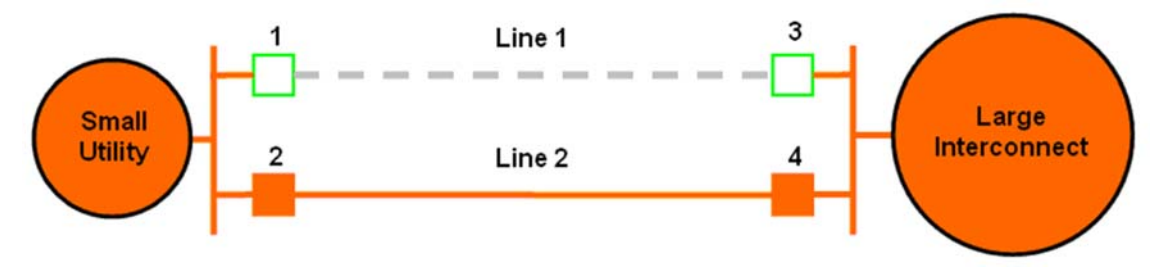


Figure 26: Line 1 is out-of-service for maintenance, Line 2 is loaded beyond its normal rating (but within its emergency rating).

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.

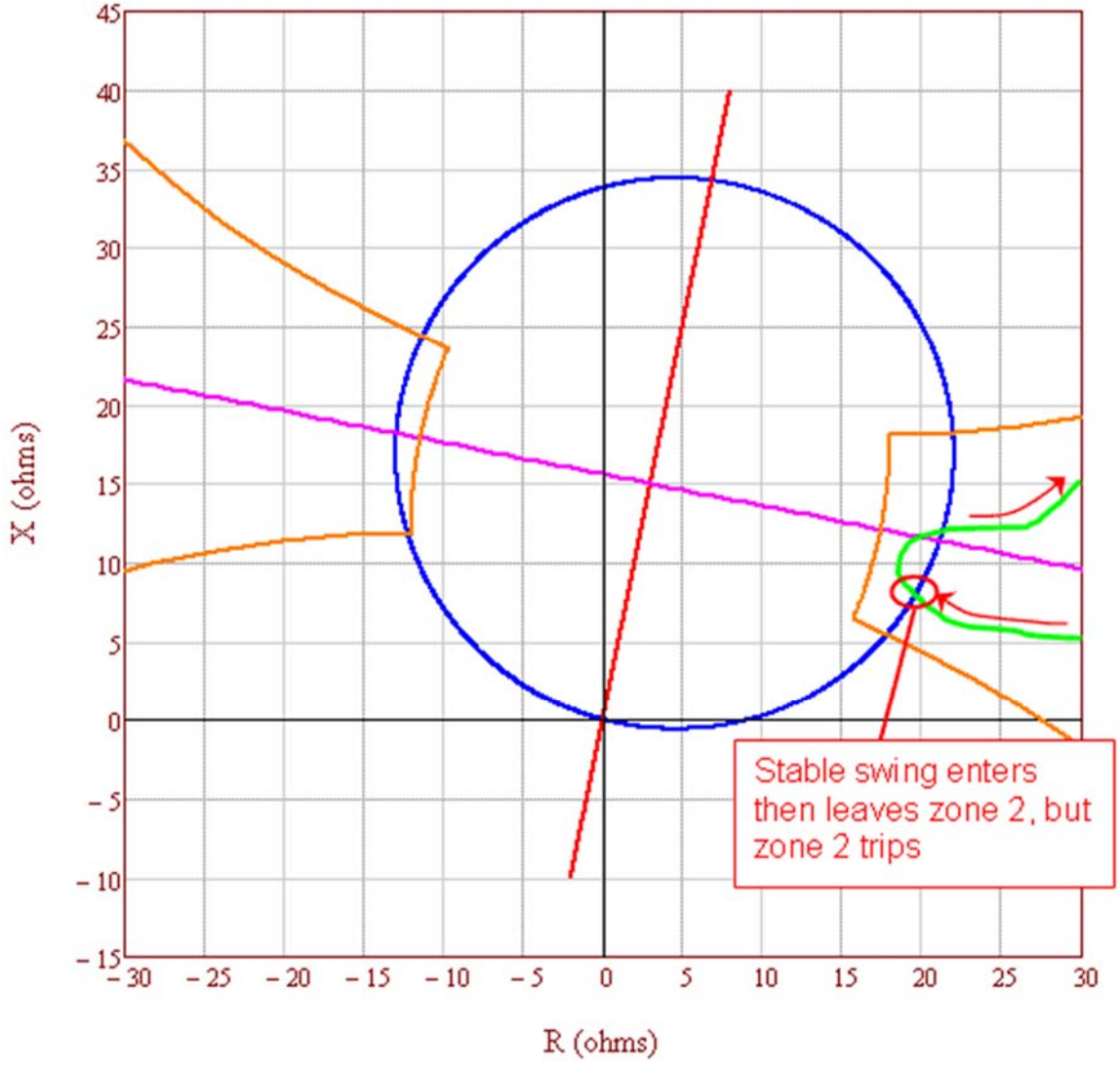


Figure 27: Relays on circuit breakers 2 and 4 were not addressed to meet the PRC-026-1 – Attachment B criteria following the previous unstable power swing event.

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.

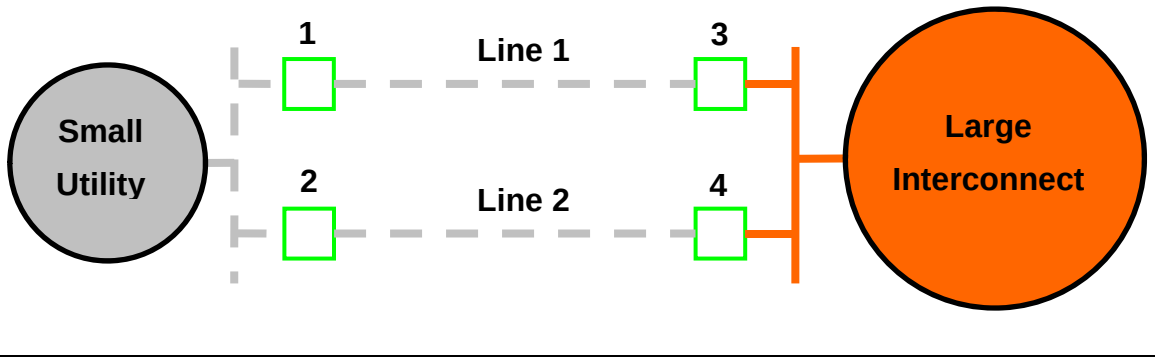


Figure 28: Possible blackout of the small utility.

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).

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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.

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

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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.

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[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.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CIP Definitions

Project 2016-02 Modifications to CIP Standards
October 29, 2018, Informal Posting

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.

Table 1: Retired, Modified, or Newly Proposed Definitions

NERC Glossary Term	Currently Approved Definition	CIP SDT Proposed New or Revised
Cyber Asset (CA)	Programmable electronic devices, including the hardware, software, and data in those devices.	A p~~P~~rogrammable electronic device~~s~~, including the physical or virtual hardware, software, and data in th~~os~~e device~~s~~.
BES Cyber System (BCS)	One or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity.	Any combination of hardware (including virtual hardware), software (including application virtualization), and data, regardless of redundancy, performing one or more reliability tasks that if rendered unavailable, degraded, or misused would result in adverse impact to one or more BES Facilities within 15 minutes.

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	Retired

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 that is: 1. capable of transmitting or transferring executable code, 2. not included in a BES Cyber System, 3. not a Protected Cyber ~~Asset~~ System (PC~~S~~A) 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~~System (BCS), • ~~network within an~~ A BES Cyber System Logical Isolation Zone ~~Electronic Security Perimeter (ESP)~~ containing high or medium impact BES Cyber Systems, or • PC~~S~~A 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 systems ~~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)	N/A	Cyber systems 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.
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.	Retired
Protected Cyber System (PCS)	N/A	Cyber systems that are able to communicate with a BES Cyber System from within the BES Cyber System's Logical Isolation Zone. The impact rating of Protected Cyber Systems is equal to the highest rated BES Cyber System within the Logical Isolation Zone.

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 – Proposed Develop EAMS and EACS
Electronic Access Control System (EACS)	N/A	Cyber systems that provide electronic access control to BES Cyber Systems.
Electronic Access Monitoring Systems (EAMS)	N/A	Cyber systems that provide electronic access monitoring of BES Cyber Systems.
Electronic Security Perimeter (ESP)	The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.	Retired
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 that is outside of its associated Logical Isolation Zone via a bi-directional routable protocol connection.

Table 1: Retired, Modified, or Newly Proposed Definitions		
NERC Glossary Term	**Currently Approved Definition**	**CIP SDT Proposed New or Revised**
Logical Isolation Zone (LIZ)	N/A	A logical security zone created by applying controls to communications to or from BES Cyber Systems and Protected Cyber Systems.
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 system acting as part of the protection applied to a logically isolated BCS that limits external user-initiated access to authorized users.
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 to a BES Cyber System or Protected Cyber System from outside of a Logical Isolation Zone. Interactive Remote Access does not include system-to-system process communications or access initiated from an Intermediate System.

Table 1: Retired, Modified, or Newly Proposed Definitions		
NERC Glossary Term	**Currently Approved Definition**	**CIP SDT Proposed New or Revised**
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 which access is controlled.
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~~System, ~~a network within an ESP,~~ or a Protected Cyber ~~Asset~~System. ~~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.~~
Secure Configuration	N/A	The implemented set of controls supporting the security objectives found within the CIP Reliability Standards where the following text exists within the requirement language: "NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system."

The Background, VRF/VSLs, and Guidelines and Technical Basis Sections have been removed for this informal posting. The Project 2016-02 is seeking comments around the concept of the Requirement/Measure language at this time. All other sections will be modified prior to the initial posting.

A. Introduction

1. **Title:** Cyber Security — Personnel & Training

2. **Number:** CIP-004-7~~6~~

3. **Purpose:** To minimize the risk against compromise that could lead to misoperation or instability in the Bulk Electric System (BES) from individuals accessing BES Cyber Systems by requiring an appropriate level of personnel risk assessment, training, and security awareness in support of protecting BES Cyber Systems.

4. **Applicability:**

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

   4.1.1. Balancing Authority

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

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

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

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

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

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

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

4.1.3. Generator Operator

4.1.4. Generator Owner~~Interchange Coordinator or Interchange Authority~~

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. Facilities: For the ~~purpose of the~~ requirements in this standard~~contained herein~~, the following Facilities, systems, and equipment owned by each Responsible Entity in 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 explicitly specified ~~explicitly~~.

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

4.2.1.1. Each UFLS or UVLS System that:

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

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

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

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

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

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

4.2.3. Exemptions: The following are exempt from Standard CIP-004-7~~6~~:

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

4.2.3.2. Cyber Assets associated with communication networks and data communication links between- BES Cyber Systems' Logical Isolation Zones~~discrete Electronic Security Perimeters~~.

4.2.3.3. Cyber Assets associated with communication networks and data communication links used to extend a Logical Isolation Zone to more than one geographic location.

~~**4.2.3.2.**~~**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.

~~**4.2.3.3.**~~**4.2.3.5.** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

~~**4.2.3.4.**~~**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-002-5.1 identification and categorization processes.

5. Effective Dates: See Implementation Plan for CIP-004-7~~6~~.

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-004-7~~6~~ Table R1 – Security Awareness Program*.

M1. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-004-7~~6~~ Table R1 – Security Awareness Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-004-7~~6~~ Table R1 – Security Awareness Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.1	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	Security awareness that, at least once each calendar quarter, reinforces cyber security practices (which may include associated physical security practices) for the Responsible Entity's personnel who have authorized electronic or authorized unescorted physical access to BES Cyber Systems.	An example of evidence may include, but is not limited to, documentation that the quarterly reinforcement has been provided. Examples of evidence of reinforcement may include, but are not limited to, dated copies of information used to reinforce security awareness, as well as evidence of distribution, such as: • direct communications (for example, e-mails, memos, computer-based training); or • indirect communications (for example, posters, intranet, or brochures); or • management support and reinforcement (for example, presentations or meetings).

R2. Each Responsible Entity shall implement one or more cyber security training program(s) appropriate to individual roles, functions, or responsibilities that collectively includes each of the applicable requirement parts in *CIP-004-7~~6~~ Table R2 – Cyber Security Training Program*.

M2. Evidence must include the training program that includes each of the applicable requirement parts in *CIP-004-7~~6~~ Table R2 – Cyber Security Training Program* and additional evidence to demonstrate implementation of the program(s).

CIP-004-7~~6~~ Table R2 – Cyber Security Training Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PACS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; and 2. PACS	Training content on: 2.1.1. Cyber security policies; 2.1.2. Physical access controls; 2.1.3. Electronic access controls; 2.1.4. The visitor control program; 2.1.5. Handling of BES Cyber System Information and its storage; 2.1.6. Identification of a Cyber Security Incident and initial notifications in accordance with the entity's incident response plan; 2.1.7. Recovery plans for BES Cyber Systems; 2.1.8. Response to Cyber Security Incidents; and 2.1.9. Cyber security risks associated with a BES Cyber System's electronic interconnectivity and interoperability with other Cyber Assets, including Transient Cyber Assets, and with Removable Media.	Examples of evidence may include, but are not limited to, training material such as power point presentations, instructor notes, student notes, handouts, or other training materials.

CIP-004-7 Table R2 – Cyber Security Training Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.2	High Impact BES Cyber Systems and their associated: 1. EACMS; and 2. PACS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EACMS; and 2. PACS	Require completion of the training specified in Part 2.1 prior to granting authorized electronic access and authorized unescorted physical access to applicable Cyber Assets, except during CIP Exceptional Circumstances.	Examples of evidence may include, but are not limited to, training records and documentation of when CIP Exceptional Circumstances were invoked.
2.3	High Impact BES Cyber Systems and their associated: 1. EACMS; and 2. PACS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EACMS; and 2. PACS	Require completion of the training specified in Part 2.1 at least once every 15 calendar months.	Examples of evidence may include, but are not limited to, dated individual training records.

R3. Each Responsible Entity shall implement one or more documented personnel risk assessment program(s) to attain and retain authorized electronic or authorized unescorted physical access to BES Cyber Systems that collectively include each of the applicable requirement parts in *CIP-004-7~~6~~ Table R3 – Personnel Risk Assessment Program*.

M3. Evidence must include the documented personnel risk assessment programs that collectively include each of the applicable requirement parts in *CIP-004-7~~6~~ Table R3 – Personnel Risk Assessment Program* and additional evidence to demonstrate implementation of the program(s).

CIP-004-7~~6~~ Table R3 – Personnel Risk Assessment Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS	Process to confirm identity.	An example of evidence may include, but is not limited to, documentation of the Responsible Entity's process to confirm identity.

CIP-004-7~~6~~ Table R3 – Personnel Risk Assessment Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.2	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS	Process to perform a seven year criminal history records check as part of each personnel risk assessment that includes: 3.2.1. current residence, regardless of duration; and 3.2.2. other locations where, during the seven years immediately prior to the date of the criminal history records check, the subject has resided for six consecutive months or more. If it is not possible to perform a full seven year criminal history records check, conduct as much of the seven year criminal history records check as possible and document the reason the full seven year criminal history records check could not be performed.	An example of evidence may include, but is not limited to, documentation of the Responsible Entity's process to perform a seven year criminal history records check.

CIP-004-7~~6~~ Table R3 – Personnel Risk Assessment Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS	Criteria or process to evaluate criminal history records checks for authorizing access.	An example of evidence may include, but is not limited to, documentation of the Responsible Entity's process to evaluate criminal history records checks.
3.4	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS	Criteria or process for verifying that personnel risk assessments performed for contractors or service vendors are conducted according to Parts 3.1 through 3.3.	An example of evidence may include, but is not limited to, documentation of the Responsible Entity's criteria or process for verifying contractors or service vendors personnel risk assessments.

CIP-004-7~~6~~ Table R3 – Personnel Risk Assessment Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.5	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS	Process to ensure that individuals with authorized electronic or authorized unescorted physical access have had a personnel risk assessment completed, except during CIP Exceptional Circumstances, according to Parts 3.1 to 3.4 within the last seven years.	An example of evidence may include, but is not limited to, documentation of the Responsible Entity's process for ensuring that individuals with authorized electronic or authorized unescorted physical access have had a personnel risk assessment completed within the last seven years.

R4. Each Responsible Entity shall implement one or more documented access management program(s) that collectively include each of the applicable requirement parts in *CIP-004-7~~6~~ Table R4 – Access Management Program.*

M4. Evidence must include the documented processes that collectively include each of the applicable requirement parts in *CIP-004-7~~6~~ Table R4 – Access Management Program* and additional evidence to demonstrate that the access management program was implemented as described in the Measures column of the table.

CIP-004-7~~6~~ Table R4 – Access Management Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ ~~1.~~2. EAMS; 3. PACS; 4. PAMS; and ~~2.~~5. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~and~~ ~~1.~~2. EAMS; 3. PACS; 4. PAMS; and ~~2.~~5. PCS	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; and 4.1.3. Access to designated storage locations (including EAMS and PAMS)~~,~~ whether physical or electronic, for BES Cyber System Information.	An example of evidence may include, but is not limited to, dated documentation of the process to authorize electronic access, unescorted physical access in a Physical Security Perimeter, and access to designated storage locations, whether physical or electronic, for BES Cyber System Information.

CIP-004-7~~6~~ Table R4 – Access Management Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.2	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ ~~1.~~2. EAMS; 3. PACS; 4. PAMS; and ~~2.~~5. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~and~~ ~~1.~~2. EAMS; 3. PACS; 4. PAMS; and ~~2.~~5. PCS	Verify at least once each calendar quarter that individuals with active electronic access or unescorted physical access have authorization records.	Examples of evidence may include, but are not limited to: • Dated documentation of the verification between the system generated list of individuals who have been authorized for access (i.e., workflow database) and a system generated list of personnel who have access (i.e., user account listing), or • Dated documentation of the verification between a list of individuals who have been authorized for access (i.e., authorization forms) and a list of individuals provisioned for access (i.e., provisioning forms or shared account listing).

CIP-004-7~~6~~ Table R4 – Access Management Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~1.~~2. EAMS; ~~and~~ 3. PACS; and ~~2.~~4. PAMS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~1.~~2. EAMS; ~~and~~ 3. PACS; and ~~2.~~4. PAMS	For electronic access, verify at least once every 15 calendar months that all user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and are those that the Responsible Entity determines are necessary.	An example of evidence may include, but is not limited to, documentation of the review that includes all of the following: 1. A dated listing of all accounts/account groups or roles within the system; 2. A summary description of privileges associated with each group or role; 3. Accounts assigned to the group or role; and 4. Dated evidence showing verification of the privileges for the group are authorized and appropriate to the work function performed by people assigned to each account.

CIP-004-7~~6~~ Table R4 – Access Management Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.4	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~1.~~2. EAMS; and 3. PACS; and ~~2.~~4. PAMS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~1.~~2. EAMS; and 3. PACS; and ~~2.~~4. PAMS	Verify at least once every 15 calendar months that access to the designated storage locations for BES Cyber System Information, whether physical or electronic, including EAMS and PAMS are correct and are those that the Responsible Entity determines are necessary for performing assigned work functions.	An example of evidence may include, but is not limited to, the documentation of the review that includes all of the following: 1. A dated listing of authorizations for BES Cyber System information; 2. Any privileges associated with the authorizations; and 3. Dated evidence showing a verification of the authorizations and any privileges were confirmed correct and the minimum necessary for performing assigned work functions.

R5. Each Responsible Entity shall implement one or more documented access revocation program(s) that collectively include each of the applicable requirement parts in *CIP-004-7~~6~~ Table R5 – Access Revocation*.

M5. Evidence must include each of the applicable documented programs that collectively include each of the applicable requirement parts in *CIP-004-7~~6~~ Table R5 – Access Revocation* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-004-7~~6~~ Table R5 – Access Revocation			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ ~~1.~~2. EAMS; 3. PACS; 4. PAMS; and ~~2.~~5. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~and~~ ~~1.~~2. EAMS; 3. PACS; 4. PAMS; and ~~2.~~5. PCS	A process to initiate removal of an individual's ability for unescorted physical access and Interactive Remote Access upon a termination action, and complete the removals within 24 hours of the termination action (Removal of the ability for access may be different than deletion, disabling, revocation, or removal of all access rights).	An example of evidence may include, but is not limited to, documentation of all of the following: 1. Dated workflow or sign-off form verifying access removal associated with the termination action; and 2. Logs or other demonstration showing such persons no longer have access.

CIP-004-7~~6~~ Table R5 – Access Revocation			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.2	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ ~~1.~~2. EAMS; 3. PACS; 4. PAMS; and ~~2.~~5. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EACMS; ~~and~~ ~~1.~~2. EAMS; 3. PACS; 4. PAMS; and ~~2.~~5. PCS	For reassignments or transfers, revoke the individual's authorized electronic access to individual accounts and authorized unescorted physical access that the Responsible Entity determines are not necessary by the end of the next calendar day following the date that the Responsible Entity determines that the individual no longer requires retention of that access.	An example of evidence may include, but is not limited to, documentation of all of the following: 1. Dated workflow or sign-off form showing a review of logical and physical access; and 2. Logs or other demonstration showing such persons no longer have access that the Responsible Entity determines is not necessary.

CIP-004-7~~6~~ Table R5 – Access Revocation			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~1.~~2. EAMS; ~~and~~ 3. PACS; and ~~2.~~4. PAMS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~1.~~2. EAMS; and 3. PACS; and ~~2.~~4. PAMS	For termination actions, revoke the individual's access to the designated storage locations for BES Cyber System Information, whether physical or electronic (unless already revoked according to Requirement R5.1), including EAMS and PAMS by the end of the next calendar day following the effective date of the termination action.	An example of evidence may include, but is not limited to, workflow or sign-off form verifying access removal to designated physical areas or cyber systems containing BES Cyber System Information associated with the terminations and dated within the next calendar day of the termination action.
5.4	High Impact BES Cyber Systems and their associated ~~:~~ EAC~~M~~S.	For termination actions, revoke the individual's non-shared user accounts (unless already revoked according to Parts 5.1 or 5.3) within 30 calendar days of the effective date of the termination action.	An example of evidence may include, but is not limited to, workflow or sign-off form showing access removal for any individual BES Cyber ~~Assets~~ Systems and software applications as determined necessary to completing the revocation of access and dated within thirty calendar days of the termination actions.

CIP-004-7~~6~~ Table R5 – Access Revocation			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.5	High Impact BES Cyber Systems and their associated ~~:~~ EAC~~M~~S.	For termination actions, change passwords for shared account(s) known to the user within 30 calendar days of the termination action. For reassignments or transfers, change passwords for shared account(s) known to the user within 30 calendar days following the date that the Responsible Entity determines that the individual no longer requires retention of that access. If the Responsible Entity determines and documents that extenuating operating circumstances require a longer time period, change the password(s) within 10 calendar days following the end of the operating circumstances.	Examples of evidence may include, but are not limited to: • Workflow or sign-off form showing password reset within 30 calendar days of the termination; • Workflow or sign-off form showing password reset within 30 calendar days of the reassignments or transfers; or • Documentation of the extenuating operating circumstance and workflow or sign-off form showing password reset within 10 calendar days following the end of the operating circumstance.

C. Compliance

1. **Compliance Monitoring Process:**

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

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

   The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

   - Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
   - If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
   - The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

   1.3. Compliance Monitoring and Assessment Processes:

   - Compliance Audits
   - Self-Certifications
   - Spot Checking
   - Compliance Violation Investigations
   - Self-Reporting
   - Complaints

   1.4. Additional Compliance Information:
   None.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated Version Number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	1/24/11	Approved by the NERC Board of Trustees.	

Version	Date	Action	Change Tracking
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-004-5.	
5.1	9/30/13	Modified two VSLs in R4	Errata
6	11/13/14	Adopted by the NERC Board of Trustees.	Addressed two FERC directives from Order No. 791 related to identify, assess, and correct language and communication networks.
6	2/12/15	Adopted by the NERC Board of Trustees.	Replaces the version adopted by the Board on 11/13/2014. Revised version addresses remaining directives from Order No. 791 related to transient devices and low impact BES Cyber Systems.
6	1/21/16	FERC order issued approving CIP-004-6. Docket No. RM15-14-000	

The Background, VRF/VSLs, and Guidelines and Technical Basis Sections have been removed for this informal posting. The Project 2016-02 is seeking comments around the concept of the Requirement/Measure language at this time. All other sections will be modified prior to the initial posting.

A. Introduction

1. **Title:** Cyber Security —-BES Cyber System Logical Isolation~~Electronic Security Perimeter(s)~~

2. **Number:** CIP-005-76

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

4. **Applicability:**

   4.1. Functional Entities: For the ~~purpose of the~~ requirements 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 explicitly 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. 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**

4.2. 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 explicitly specified. ~~explicitly.~~

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

4.2.1.1 Each UFLS or UVLS System that:

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

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

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

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

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

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

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-005-7~~6~~:

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

4.2.3.2. Cyber Assets associated with communication networks and data communication links between BES Cyber Systems' Logical Isolation Zones~~discrete Electronic Security Perimeters~~.

~~**4.2.3.2.**~~**4.2.3.3.** Cyber Assets associated with communication networks and data communication links used to extend a Logical Isolation Zone to more than one 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.

5. Effective Date:

See Implementation Plan for ~~Project 2016-03~~CIP-005-7.

B. Requirements and Measures

R1. Each Responsible Entity shall implement one or more documented processes to mitigate the risk posed by unauthorized communications to and from applicable systems ~~-~~that collectively include each of the applicable requirement parts in *CIP-005-7~~6~~ Table R1 –* *Logical Isolation Zones.* These processes exclude consideration of time-sensitive protection or control functions between intelligent electronic devices (e.g., communications using protocol IEC TR-61850-90-5 R-GOOSE) ~~*Electronic Security Perimeter*~~.

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 Zones* ~~*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~~Logical Isolation Zones			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.~~3~~	~~Electronic Access Points for~~ High Impact BES Cyber Systems ~~Electronic Access Points for~~ Medium Impact BES Cyber Systems	Have one or more methods to logically isolate applicable systems, either individually or as a group, by only allowing: 1.1.1. ~~Require~~Communication that has documented inbound and outbound access permissions, including the reason for granting access; and~~, and deny all other access by default.~~ 1.2.1. Serial port connectivity such as RS-232 and RS-485. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	Evidence may include, but is not limited to, configuration of systems that enforce logical isolation such as network infrastructure configuration (ACL, VLAN, VXLAN, MPLS), compute configuration (e.g., Hypervisor, containers), storage system configuration (e.g., SAN, NAS, DAS). ~~An example of evidence may include, but is not limited to, a list of rules (firewall, access control lists, etc.) that demonstrate that only permitted access is allowed and that each access rule has a documented reason.~~

CIP-005-6 Table R1 – ~~Electronic Security Perimeter~~Logical Isolation Zones			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.2	High Impact BES Cyber Systems and their associated PCS Medium Impact BES Cyber Systems and their associated PCS	Protect the data traversing communication networks used to provide connectivity between components of a Logically Isolated Zone that spans multiple geographic locations to preserve confidentiality and integrity.	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.
1.3~~4~~	High Impact BES Cyber Systems with Dial-up Connectivity and their associated PCS ~~A~~ Medium Impact BES Cyber Systems with Dial-up Connectivity and their associated PCS~~A~~	~~Where technically feasible,~~ P~~p~~erform authentication when establishing Dial-up Connectivity with applicable Cyber Assets~~.~~ 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.
1.4~~5~~	~~Electronic Access Points for~~ High Impact BES Cyber Systems and their associated PCS ~~Electronic Access Points for~~ Medium Impact BES Cyber Systems at Control Centers and their associated PCS	Have one or more methods for detecting known or suspected malicious inbound and outbound communications to and from applicable systems either individually or as grouped in Part 1.1, excluding serial port connectivity such as RS-232 and RS-485.	~~An example of e~~Evidence may include, but is not limited to, documentation that malicious communications detection methods (e.g. intrusion detection system, application layer firewall, privileged introspection, etc.) are implemented.

R2. Each Responsible Entity shall implement one or more documented processes to mitigate the risk posed by exploitation of Interactive Remote Access that collectively include the applicable requirement parts, where technically feasible, per system capability, in *CIP-005-6 Table R2 –Remote Access Management*.

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

CIP-005-7 Table R2 —Remote Access Management Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact BES Cyber Systems and their associated : PCS A Medium Impact BES Cyber Systems with External Routable Connectivity and their associated : PCSA	Have one or more methods to For all Interactive ensure that Interactive Remote Access, to applicable systems is through an Intermediate System that is isolated from the BES Cyber System and restricts Interactive Remote Access to only authorized users. 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 is not limited to, network diagrams or architecture documents.
2.2	High Impact BES Cyber Systems and their associated : PCS A Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:	Have one or more methods to mitigate the risks posed by unauthorized modification and unauthorized disclosure of data during For all Interactive Remote Access sessions, that terminate at an Intermediate System utilize	An example of eEvidence may include, but is not limited to, architecture documents detailing the methods used to mitigate the risk of unauthoreized disclosure. Examples include illustrating where encryption initiates and terminates.

CIP-005-76 Table R2 ~~– Remote Access Management~~ Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
	~~•~~ PCSA	~~encryption that terminates at an Intermediate System~~.	
2.3	High Impact BES Cyber Systems and their associate ~~d:~~ PCS ~~A~~ Medium Impact BES Cyber Systems ~~with External Routable Connectivity~~ and their associated PCSA	Have one or more methods to ~~R~~require multi-factor authentication for all Interactive Remote Access sessions.	~~An example of e~~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.~~

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CIP-005-76 Table R2 — Remote Access Management Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.4	High Impact BES Cyber Systems and their associatedassociated : PCS A Medium Impact BES Cyber Systems with External Routable Connectivity and their associated : PCSA	Have one or more methods for determining active vendor remote access sessions (including Interactive Remote Access and system-to-system remote access).	Examples of eEvidence may include, but isare not limited to documented methods such as: • Methods for accessing logged information 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 requiring vendors to call and request calling and requesting a second factor toin order to initiate remote access.

CIP-005-7~~6~~ Table R2 ~~– Remote Access Management~~ Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.5	High Impact BES Cyber Systems and their associated • PCS ~~A~~ Medium Impact BES Cyber Systems ~~with External Routable Connectivity~~ and their associated • PCS~~A~~	Have one or more method(s) to disable active vendor remote access (including Interactive Remote Access and system-to-system remote access).	~~Examples of e~~Evidence may include, but ~~are~~ is not limited to, documented~~ion 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.

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R3. Each Responsible Entity shall implement one or more documented processes to mitigate the risk posed by unrestricted access for communication between the management plane~~.~~[1] and the data plane[2] that collectively include the applicable requirement parts, in *CIP-005-6 Table R3* – Isolation of Management Plane and Data Plane.

[1] Management plane of a system is that element that configures, monitors, and provides management, monitoring and configuration services to, all layers of the network stack and other parts of the system.

[2] Data plane (sometimes known as the user plane, forwarding plane, carrier plane or bearer plane) is the part of a network that carries user traffic.

M3. Evidence must include the documented processes that collectively address each of the applicable requirement parts in *CIP-005-6 Table R3* – Isolation of Management Plane and Data Plane and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-005-6 Table R3 – Isolation of Management Plane and Data Plane			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.1	High Impact BES Cyber Systems and their associated: 1. EACS 2. PCS Medium Impact BES Cyber Systems and their associated PCS: 1. EACS 2. PCS	Have one or more methods per system capability to: 1. Restrict access to the management plane; and 2. Logically isolate the management plane from the data plane.	An example of evidence may include but is not limited to documentation that includes the following: Configuration of systems that enforce authentication and logical isolation such as network infrastructure configuration (ACL, VLAN, VXLAN, MPLS), compute configuration (e.g. Hypervisor, containers), storage system configuration (e.g. SAN, NAS, DAS).

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.

   - Each applicable entity shall retain evidence of each requirement in this standard for three calendar years.
   - If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
   - The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

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

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3 Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-005-5.	
6	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.	

The Background, VRF/VSLs, and Guidelines and Technical Basis Sections have been removed for this informal posting. The Project 2016-02 is seeking comments around the concept of the Requirement/Measure language at this time. All other sections will be modified prior to the initial posting.

A. Introduction

1. Title: Cyber Security — Physical Security of BES Cyber Systems

2. Number: CIP-006-7~~6~~

3. Purpose: To manage physical access to Bulk Electric System (BES) Cyber Systems by specifying a physical security plan in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.

4. Applicability:

4.1. Functional Entities: For the ~~purpose of the~~ requirements 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 explicitly specified ~~explicitly~~.

4.1.1 Balancing Authority

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

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

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

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

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

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

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

4.1.3 Generator Operator

4.1.4 Generator Owner

~~**4.1.5 Interchange Coordinator or Interchange Authority**~~

~~**4.1.6**~~**4.1.5 Reliability Coordinator**

~~**4.1.7**~~**4.1.6 Transmission Operator**

~~**4.1.8**~~**4.1.7 Transmission Owner**

4.2. Facilities: For the ~~purpose of the~~ requirements in this standard~~contained herein~~, the following Facilities, systems, and equipment owned by each Responsible Entity in 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 explicitly specified ~~explicitly~~.

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

4.2.1.1 Each UFLS or UVLS System that:

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

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

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

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

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

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard ~~CIP-006-6~~CIP-006-7:

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

4.2.3.2 Cyber Assets associated with communication networks and data communication links between~~-~~ BES Cyber Systems' Logical Isolation Zones. ~~discrete Electronic Security Perimeters~~.

4.2.3.3 Cyber Assets associated with communication networks and data communication links used to extend a Logical Isolation Zone to more than one geographic location.

~~**4.2.3.2**~~**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.

~~**4.2.3.3**~~**4.2.3.5** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

~~**4.2.3.4**~~**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-002-5.1 identification and categorization processes.

5. Effective Dates:

See Implementation Plan for CIP-006-7~~6~~.

B. Requirements and Measures

R1. Each Responsible Entity shall implement~~, except during CIP Exceptional Circumstances,~~ one or more documented physical security plan(s) that collectively include all of the applicable requirement parts in *CIP-006-7~~6~~ Table R1 – Physical Security Plan*.

M1. Evidence must include each of the documented physical security plans that collectively include all of the applicable requirement parts in *CIP-006-7~~6~~ Table R1 – Physical Security Plan* and additional evidence to demonstrate implementation of the plan or plans as described in the Measures column of the table.

CIP-006-7~~6~~ Table R1 – Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.1	Medium Impact BES Cyber Systems without External Routable Connectivity Physical Access Control Systems (PACS) associated with: • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity • ~~Programmable electronic device without External Routable Connectivity (ERC)~~	Define operational or procedural controls to restrict physical access.	An example of evidence may include, but is not limited to, documentation that operational or procedural controls exist.

CIP-006-7 Table R1 – Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.2	Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EACMS; and 2. PCSA	Use ~~utilize~~ at least one physical access control to allow unescorted physical access into each applicable Physical Security Perimeter to only those individuals who have authorized unescorted physical access.	An example of evidence may include, but is not limited to, language in the physical security plan that describes each Physical Security Perimeter and how unescorted physical access is controlled by one or more different methods and proof that unescorted physical access is restricted to only authorized individuals, such as a list of authorized individuals accompanied by access logs.

CIP-006-7~~6~~ Table R1 – Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PCS~~A~~	Where technically feasible, use~~tilize~~ two or more different physical access controls (this does not require two completely independent physical access control systems) to collectively allow unescorted physical access into Physical Security Perimeters to only those individuals who have authorized unescorted physical access.	An example of evidence may include, but is not limited to, language in the physical security plan that describes the Physical Security Perimeters and how unescorted physical access is controlled by two or more different methods and proof that unescorted physical access is restricted to only authorized individuals, such as a list of authorized individuals accompanied by access logs.

CIP-006-7~~6~~ Table R1– Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.4	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A	Monitor for unauthorized access through a physical access point into a Physical Security Perimeter.	An example of evidence may include, but is not limited to, documentation of controls that monitor for unauthorized access through a physical access point into a Physical Security Perimeter.

CIP-006-7~~6~~ Table R1– Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.5	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A	Issue an alarm or alert in response to detected unauthorized access through a physical access point into a Physical Security Perimeter to the personnel identified in the BES Cyber Security Incident response plan within 15 minutes of detection.	An example of evidence may include, but is not limited to, language in the physical security plan that describes the issuance of an alarm or alert in response to unauthorized access through a physical access control into a Physical Security Perimeter and additional evidence that the alarm or alert was issued and communicated as identified in the BES Cyber Security Incident Response Plan, such as manual or electronic alarm or alert logs, cell phone or pager logs, or other evidence that documents that the alarm or alert was generated and communicated.
1.6	Physical Access Control Systems (PACS) associated with: • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity	Monitor each Physical Access Control System for unauthorized physical access to a Physical Access Control System.	An example of evidence may include, but is not limited to, documentation of controls that monitor for unauthorized physical access to a PACS.

CIP-006-7 Table R1– Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.7	Physical Access Control Systems (PACS) associated with: • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity	Issue an alarm or alert in response to detected unauthorized physical access to a Physical Access Control System to the personnel identified in the BES Cyber Security Incident response plan within 15 minutes of the detection.	An example of evidence may include, but is not limited to, language in the physical security plan that describes the issuance of an alarm or alert in response to unauthorized physical access to Physical Access Control Systems and additional evidence that the alarm or alerts was issued and communicated as identified in the BES Cyber Security Incident Response Plan, such as alarm or alert logs, cell phone or pager logs, or other evidence that the alarm or alert was generated and communicated.

CIP-006-7~~6~~ Table R1 – Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.8	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PCS~~A~~ Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; and 2. PCS~~A~~	Log (through automated means or by personnel who control entry) entry of each individual with authorized unescorted physical access into each Physical Security Perimeter, with information to identify the individual and date and time of entry, except during CIP Exceptional Circumstances.	An example of evidence may include, but is not limited to, language in the physical security plan that describes logging and recording of physical entry into each Physical Security Perimeter and additional evidence to demonstrate that this logging has been implemented, such as logs of physical access into Physical Security Perimeters that show the individual and the date and time of entry into Physical Security Perimeter.

CIP-006-7 Table R1 – Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.9	High Impact BES Cyber Systems and their associated: 1. EACMS; and 2. PCSA Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EACMS; and 2. PCSA	Retain physical access logs of entry of individuals with authorized unescorted physical access into each Physical Security Perimeter for at least ninety calendar days, except during CIP Exceptional Circumstances.	An example of evidence may include, but is not limited to, dated documentation such as logs of physical access into Physical Security Perimeters that show the date and time of entry into Physical Security Perimeter.

~~CIP-006-6~~CIP-006-7 Table R1 – Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.10	High Impact BES Cyber Systems and their associated PC~~S~~A Medium Impact BES Cyber Systems at Control Centers and their associated ~~:~~ PC~~S~~A	Restrict physical access to cabling and other nonprogrammable communication components used for ~~for connection between~~ applicable ~~Cyber Assets~~systems ~~within~~ in the same ~~isolated BES Cyber System~~~~Electronic Security~~Logical Isolation Zone ~~Perimeter~~ -in those instances when such cabling and components are located outside of a Physical Security Perimeter. Where physical access restrictions to such cabling and components are not implemented, the Responsible Entity shall document and implement one or more of the following: • encryption of data that transits such cabling and components; or • monitoring the status of the communication link composed of such cabling and components and issuing an alarm or alert in response to detected communication failures to the personnel identified in the BES Cyber Security Incident response plan within 15 minutes of detection; or • an equally effective logical protection.	An example of evidence may include, but is not limited to, records of the Responsible Entity's implementation of the physical access restrictions (e.g., cabling and components secured through conduit or secured cable trays) encryption, monitoring, or equally effective logical protections.

R2. Each Responsible Entity shall implement, except during CIP Exceptional Circumstances, ~~-~~one or more documented visitor control program(s) that include each of the applicable requirement parts in *CIP-006-~~7~~6 Table R2 – Visitor Control Program.*

M2. Evidence must include one or more documented visitor control programs that collectively include each of the applicable requirement parts in *CIP-006-~~7~~6 Table R2 – Visitor Control Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-006-~~7~~6 Table R2 – Visitor Control Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A	Require continuous escorted access of visitors (individuals who are provided access but are not authorized for unescorted physical access) within each Physical Security Perimeter~~,~~ ~~except during CIP Exceptional Circumstances~~.	An example of evidence may include, but is not limited to, language in a visitor control program that requires continuous escorted access of visitors within Physical Security Perimeters and additional evidence to demonstrate that the escorted access process was implemented, such as visitor logs.

CIP-006-7~~6~~ Table R2 – Visitor Control Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.2	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A	Require manual or automated logging of visitor entry into and exit from the Physical Security Perimeter that includes date and time of the initial entry and last exit, the visitor's name, and the name of an individual point of contact responsible for the visitor~~, except during CIP Exceptional Circumstances~~.	An example of evidence may include, but is not limited to, language in a visitor control program that requires continuous escorted access of visitors within Physical Security Perimeters and additional evidence to demonstrate that the escorted access process was implemented, such as dated visitor logs that include the required information.
2.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A	Retain visitor logs for at least ninety calendar days.	An example of evidence may include, but is not limited to, documentation showing logs have been retained for at least ninety calendar days.

R3. Each Responsible Entity shall implement one or more documented Physical Access Control System maintenance and testing program(s) that collectively include each of the applicable requirement parts in *CIP-006-7~~6~~ Table R3 – Maintenance and Testing Program*.

M3. Evidence must include each of the documented Physical Access Control System maintenance and testing programs that collectively include each of the applicable requirement parts in *CIP-006-7~~6~~ Table R3 – Maintenance and Testing Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-006-7~~6~~ Table R3 – Physical Access Control System Maintenance and Testing Program			
Part	**Applicable Systems**	**Requirement**	**Measures**
3.1	Physical Access Control Systems (PACS) associated with: • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity Locally mounted hardware or devices at the Physical Security Perimeter associated with: • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity	Maintenance and testing of each Physical Access Control System and locally mounted hardware or devices at the Physical Security Perimeter at least once every 24 calendar months to ensure they function properly.	An example of evidence may include, but is not limited to, a maintenance and testing program that provides for testing each Physical Access Control System and locally mounted hardware or devices associated with each applicable Physical Security Perimeter at least once every 24 calendar months, Also, ~~and~~ additional evidence such as dated maintenance records or other documentation ~~to demonstrate that this testing was done, such as dated maintenance records, or other documentation~~ to demonstrate that ~~showing~~ testing and maintenance has been performed on each applicable device or system at least once every 24 calendar months.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information:

None

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated Version Number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	1/24/11	Approved by the NERC Board of	

Version	Date	Action	Change Tracking
		Trustees.	
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-006-5.	
6	11/13/14	Adopted by the NERC Board of Trustees.	Addressed FERC directives from Order No. 791.
6	1/21/16	FERC order issued approving CIP-006-6. Docket No. RM15-14-000	

The Background, VRF/VSLs, and Guidelines and Technical Basis Sections have been removed for this informal posting. The Project 2016-02 is seeking comments around the concept of the Requirement/Measure language at this time. All other sections will be modified prior to the initial posting.

A. Introduction

1. **Title:** Cyber Security — System Security Management

2. **Number:** CIP-007-7~~6~~

3. **Purpose:** To manage system security by specifying select technical, operational, and procedural requirements in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).

4. **Applicability:**

   4.1. Functional Entities: For the ~~purpose of the~~ requirements 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 explicitly specified~~. explicitly.~~

   4.1.1. Balancing Authority

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

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

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

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

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

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

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

4.1.3. Generator Operator

4.1.4. Generator Owner~~Interchange Coordinator or Interchange Authority~~

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. Facilities: For the ~~purpose of the~~ requirements in this standard~~contained herein~~, the following Facilities, systems, and equipment owned by each Responsible Entity in 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 explicitly specified. ~~explicitly.~~

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

4.2.1.1. Each UFLS or UVLS System that:

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

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

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

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

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

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

4.2.3. Exemptions: The following are exempt from Standard CIP-007-7~~6~~:

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

4.2.3.2. Cyber Assets associated with communication networks and data communication links between BES Cyber Systems' Logical Isolation Zones (LIZ).~~discrete Electronic Security Perimeters.~~

4.2.3.3. Cyber Assets associated with communication networks and data communication links used to extend a Logical Isolation Zone to more than one 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-002-5.1 identification and categorization processes.

5. Effective Dates: See Implementation Plan for CIP-007-7~~6~~.

B. Requirements and Measures

R1. Each Responsible Entity shall implement one or more documented process(es) to mitigate the risk posed by uncontrolled logical and physical connectivity that collectively include each of the applicable requirement parts in *CIP-007-7~~6~~ Table R1 – ~~Ports and Services~~Connectivity*.

M1. Evidence must include the documented processes that collectively include each of the applicable requirement parts in *CIP-007-7~~6~~ Table R1 – ~~Ports and Services~~Connectivity* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-~~6~~7 Table R1– ~~Ports and Services~~Connectivity			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems ~~with External Routable Connectivity~~ and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~	~~Where technically feasible, enable only logical network accessible ports that have been determined to be needed by the Responsible Entity, including port ranges or services where needed to handle dynamic ports. If a device has no provision for disabling or restricting logical ports on the device then those ports that are open are deemed needed.~~ Use one or a combination of the following methods (per system capability) excluding serial port connectivity such as RS-232 and RS-485: • Configure each system to provide only essential logical connectivity; • Detect and alert on malicious communication within systems; ~~or~~ • Baseline system logical connectivity, and alert on deviation from baseline; or • Other method(s) to mitigate the risk posed by uncontrolled logical connectivity. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	Examples of evidence may include, but are not limited to: • Documentation of the need for ~~all enabled ports on~~ all enabled logical ports. ~~applicable Cyber Assets and Electronic Access Points, individually or by group.~~ • Listings of logical ~~the~~ listening ports on the ~~Cyber Assets~~ applicable systems, individually or by group, from either the device configuration files, command output (such as netstat), or network scans of open ports; or • Configuration files of host-based firewalls or other device level mechanisms that only allow needed ports and deny all others. • Documentation that malicious communications detection methods (e.g. intrusion detection system, application layer firewall, privileged introspection, etc.) are implemented within systems. • Any necessary combination of configuration files of system connectivity, storage connectivity, or network connectivity.

CIP-007-~~6~~7 Table R1– ~~Ports and Services~~Connectivity			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.2	High Impact BES Cyber Systems and their associated: 1. PC~~S~~SA; and 2. Nonprogrammable communication components located inside both a PSP and a~~n ESP~~LIZ. Medium Impact BES Cyber Systems at Control Centers and their associated: 1. PC~~S~~SA; and 2. Nonprogrammable communication components located inside both a PSP and a~~n ESP~~LIZ.	Protect against the use of unnecessary physical input/output ports used for network connectivity, console commands, or Removable Media.	An example of evidence may include, but is not limited to, documentation showing types of protection of physical input/output ports, either logically through system configuration or physically using a port lock or signage.

R2. Each Responsible Entity shall implement one or more documented process(es) to mitigate the risk posed by unmanaged software that collectively include each of the applicable requirement parts in *CIP-007-7~~6~~ Table R2 – ~~Security Patch~~ Software Management*.

M2. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-007-~~6~~7 Table R2 – ~~Security Patch~~Software Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-7 Table R2 – ~~Security Patch~~Software Management			
Part	Applicable Systems	Requirements	Measures

2.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~	~~A patch management process for tracking, evaluating, and installing cyber security patches for applicable Cyber Assets. The tracking portion shall include the identification of a source or sources that the Responsible Entity tracks for the release of cyber security patches for applicable Cyber Assets that are updateable and for which a patching source exists.~~ Use one or a combination of the following methods (per system capability) to allow only essential software execution, as determined by the Responsible Entity: • Configure each system with intentionally installed essential software and executable scripts; • Baseline currently installed software and executable scripts and alert on any newly installed software or executable scripts; • Implement application whitelisting; ~~or~~ • Use read-only bootable media; or • Other methods to mitigate the risk posed by unmanaged software. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	An example of evidence may include, but is not limited to:~~, documentation of a patch management process and documentation or lists of sources that are monitored, whether on an individual BES Cyber System or Cyber Asset basis.~~ • Documentation of essential software and executable scripts; • Application whitelisting rule sets; • Documentation of read-only bootable media configuration; or • Documentation of other methods.

R3. Each Responsible Entity shall implement one or more documented process(es) to mitigate the risk posed by malicious code that collectively include each of the applicable requirement parts in *CIP-007-7~~6~~ Table R3 – Malicious Code Prevention*.

M3. Evidence must include each of the documented processes that collectively include each of the applicable requirement parts in *CIP-007-7~~6~~ Table R3 – Malicious Code Prevention* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-7~~6~~ Table R3 – Malicious Code Prevention			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~	Deploy method(s) to deter, detect, or prevent malicious code. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	An example of evidence may include, but is not limited to, records of the Responsible Entity's performance of these processes (e.g., through traditional antivirus, system hardening, policies, etc.).

CIP-007-7~~6~~ Table R3 – Malicious Code Prevention			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.2	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~	Mitigate the threat of detected malicious code. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	Examples of evidence may include, but are not limited to: • Records of response processes for malicious code detection • Records of the performance of these processes when malicious code is detected.
3.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~	For those methods identified in Part 3.1 that use signatures or patterns, have a process for the update of the signatures or patterns. The process must address testing and installing the signatures or patterns.	An example of evidence may include, but is not limited to, documentation showing the process used for the update of signatures or patterns.

R4. Each Responsible Entity shall implement, except during CIP Exceptional Circumstances, one or more documented process(es) to monitor security events to mitigate the risk posed by detectable security incidents that collectively include each of the applicable requirement parts in *CIP-007-6 Table R4 – Security Event Monitoring*.

M4. Evidence must include each of the documented processes that collectively include each of the applicable requirement parts in *CIP-007-7~~6~~ Table R4 – Security Event Monitoring* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-6 Table R4 – Security Event Monitoring			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCSA Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCSA	Log events ~~at the BES Cyber System level~~ (per ~~BES Cyber S~~system capability~~) or at the Cyber Asset level (per Cyber Asset capability~~) for identification ~~of,~~ and ~~after the fact~~ subsequent investigations of~~,~~ Cyber Security Incidents that include~~s, as a minimum,~~ each of the following types of events: 4.1.1. Detected successful login attempts; 4.1.2. Detected failed access attempts and failed login attempts; 4.1.3. Detected malicious code. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	Examples of evidence may include, but are not limited to, a paper or system generated listing of event types that the ~~for which the~~ BES Cyber System ~~is capable of~~can detect~~ing~~ and, for generated events, is configured to log. This listing must include the required types of events.

CIP-007-6 Table R4 – Security Event Monitoring			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.2	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~SA Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~SA	Generate alerts for security events that the Responsible Entity determines need ~~necessitates~~ an alert, that include~~s~~, as a minimum, each of the following types of events (per ~~Cyber Asset or BES Cyber S~~system capability): 4.2.1. Detected malicious code from Part 4.1; and 4.2.2. Detected failure of Part 4.1 event logging. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	Examples of evidence may include, but are not limited to, paper or system-generated list~~sing~~ of security events that the Responsible Entity determined nee~~ded~~~~cessitate~~ alerts, including paper or system generated lists showing how alerts are configured.

CIP-007-6 Table R4 – Security Event Monitoring			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~SA Medium Impact BES Cyber Systems at Control Centers and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~SA	~~Per system capability~~ ~~Where technically feasible, r~~Retain applicable event logs identified in Part 4.1 per system capability for at least the last 90 consecutive calendar days. ~~except under CIP Exceptional Circumstances.~~	Examples of evidence may include, but are not limited to, documentation of the event log retention process and paper or system generated reports showing log retention configuration set at 90 days or greater.
4.4	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PC~~S~~SA	Review a summarization or sampling of logged events as determined by the Responsible Entity at intervals no greater than 15 calendar days to identify undetected Cyber Security Incidents.	Examples of evidence may include, but are not limited to, documentation describing the review, ~~any~~ findings from the review (if any), and dated documentation showing the review occurred.

R5. Each Responsible Entity shall implement one or more documented process(es) to mitigate the risk posed by unauthorized electronic access that collectively include each of the applicable requirement parts in *CIP-007-7~~6~~ Table R5 – System Access Controls*.

M5. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-007-~~6~~7 Table 5 – System Access Controls* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-7~~6~~ Table R5 – System Access Controls			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems at Control Centers and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~	Have a method(s) to enforce authentication of interactive user access, ~~where technically feasible.~~ per system capability. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	An example of evidence may include, but is not limited to, documentation describing how access is authenticated.

CIP-007-7~~6~~ Table R5 – System Access Control			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.2	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~	Identify and inventory all known enabled default or other generic account types, either by system, by groups of systems, by location~~,~~ or by system type(s). NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	An example of evidence may include, but is not limited to, a listing of accounts by account types showing the enabled or generic account types in use for the BES Cyber System.
5.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~	Identify individuals who have authorized access to shared accounts.	An example of evidence may include, but is not limited to, listing of shared accounts and the individuals who have authorized access to each shared account.

CIP-007-6 Table R5 – System Access Control			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.4	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A	Change known default passwords, per ~~Cyber Asset~~system capability	Examples of evidence may include, but are not limited to: • Records of a procedure that passwords are changed when new devices are put in production; or • Documentation in system manuals or other vendor documents showing default vendor passwords were generated pseudo-randomly and are thereby unique to the device.
5.5	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A	For password-only authentication for interactive user access, either technically or procedurally enforce the following password parameters: 5.5.1. Password length that is, at least, the lesser of eight characters or the maximum length supported by the ~~Cyber Asset~~system; and 5.5.2. ~~5.5.2~~ Minimum password complexity that is the lesser of three or more different types of characters (e.g., uppercase alphabetic, lowercase alphabetic, numeric, non-alphanumeric) or the maximum complexity supported by the ~~Cyber Asset~~system.	Examples of evidence may include, but are not limited to: • System-generated reports or screen-shots of the system-enforced password parameters, including length and complexity; or • Attestations that include a reference to the documented procedures that were followed.

		NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	

CIP-007-7~~6~~ Table R5 – System Access Control			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.6	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~	~~Where technically feasible~~Per system capability, for password-only authentication for interactive user access, either technically or procedurally enforce password changes or an obligation to change the password at least once every 15 calendar months. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	Examples of evidence may include, but are not limited to: • System-generated reports or screen-shots of the system-enforced periodicity of changing passwords; or • Attestations that include a reference to the documented procedures that were followed.
5.7	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems at Control Centers and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~	~~Where technically feasible~~Per system capability, either: • Limit the number of unsuccessful authentication attempts; or • Generate alerts after a threshold of unsuccessful authentication attempts. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	Examples of evidence may include, but are not limited to: • Documentation of the account-lockout parameters; or • Rules in the alerting configuration showing how the system notified individuals after a determined number of unsuccessful login attempts.

C. Compliance

1. **Compliance Monitoring Process:**

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

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

- The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:
- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.4. Additional Compliance Information:

None.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated Version Number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	1/24/11	Approved by the NERC Board of Trustees.	

Version	Date	Action	Change Tracking
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-007-5.	
6	11/13/14	Adopted by the NERC Board of Trustees.	Addressed two FERC directives from Order No. 791 related to identify, assess, and correct language and communication networks.
6	2/15/15	Adopted by the NERC Board of Trustees.	Replaces the version adopted by the Board on 11/13/2014. Revised version addresses remaining directives from Order No. 791 related to transient devices and low impact BES Cyber Systems.
6	1/21/16	FERC order issued approving CIP-007-6. Docket No. RM15-14-000	

The Background, VRF/VSLs, and Guidelines and Technical Basis Sections have been removed for this informal posting. The Project 2016-02 is seeking comments around the concept of the Requirement/Measure language at this time. All other sections will be modified prior to the initial posting.

A. Introduction

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

2. **Number:** CIP-010-~~4~~3

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

4. **Applicability:**

   4.1. Functional Entities: For the ~~purpose of the~~ requirements 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 explicitly 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

4.2. Facilities: For ~~the purpose of~~ the requirements ~~contained herein~~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, systems, or equipment or subset of Facilities, systems, and equipment are applicable, these are explicitly specified~~. explicitly.~~

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

4.2.1.1 Each UFLS or UVLS System that:

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

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

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

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

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

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

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-010-~~3~~4:

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

4.2.3.2. Cyber Assets associated with communication networks and data communication links between BES Cyber Systems' Logical Isolation Zones (LIZ).~~discrete Electronic Security Perimeters~~.

~~**4.2.3.2.**~~**4.2.3.3.** Cyber Assets associated with communication networks and data communication links used to extend a Logical Isolation Zone to more than one 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.

5. Effective Date:

See Implementation Plan for ~~Project 2016-03~~CIP-010-4.

B. Requirements and Measures

R1. Each Responsible Entity shall implement one or more documented process(es) to mitigate the risk posed by insecure system configuration that collectively include each of the applicable requirement parts in *CIP-010-~~3~~4 Table R1 – Secure Configuration ~~Change~~ Management*.

M1. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-~~3~~4 Table R1 – Secure Configuration ~~Change~~ Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-010-~~3~~4 Table R1 – Secure Configuration ~~Change~~ Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
~~1.1~~	~~High Impact BES Cyber Systems and their associated:~~ ~~1. EACMS;~~ ~~2. PACS; and~~ ~~3. PCA~~ ~~Medium Impact BES Cyber Systems and their associated:~~ ~~1. EACMS;~~ ~~2. PACS; and~~ ~~3. PCA~~	~~Develop a baseline configuration, individually or by group, which shall include the following items:~~ ~~1.1.1. Operating system(s) (including version) or firmware where no independent operating system exists;~~ ~~1.1.2. Any commercially available or open-source application software (including version) intentionally installed;~~ ~~1.1.3. Any custom software installed;~~ ~~1.1.4. Any logical network accessible ports; and~~ ~~1.1.5. Any security patches applied.~~	~~Examples of evidence may include, but are not limited to:~~ ~~• Documentation A spreadsheet identifying the required items of the baseline secure configuration for each Cyber Assetsystem, individually or by group.; or~~ ~~A record in an asset management system that identifies the required items of the baseline configuration for each Cyber Asset, individually or by group.~~

1.1~~2~~	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~	Control change to the S~~s~~ecure C~~c~~onfiguration ~~described in CIP-010 Requirement R1 Part 1.1~~ implemented on systems through: ~~Authorize and document changes that deviate from the existing baseline configuration.~~ ~~1.1.1.~~ 1.1.1. Authorization; 1.1.2. Prior to the change, determine required cyber security controls in the Secure Configuration that could be impacted by the change; 1.1.3. Implementation; and 1.1.4. Following the change, verify that required cyber security ~~controls determined~~controls determined in 1.1.2 are not adversely affected~~;~~ and document the results. ~~:~~ The process requirements of Parts 1.1.1 through 1.1.4 and timeline are based on the analysis of the risk to BES reliability and the risk posed by the change to the system(s).	Examples of evidence may include, but are not limited to: • ~~A change request record and~~ R~~r~~ecords ~~for~~of authorization~~associated electronic authorization (performed by the individual or group with the authority to authorize the change) in a change management system for each change; or~~ • Records of ~~testing~~controls impact ~~evaluaton~~evaluation; • Records of implementation; and • Records of ~~evaluation~~verification. ~~Documentation that the change was performed in accordance with the requirement.~~

CIP-010-~~4~~3 Table R1 – Secure Configuration ~~Change~~ Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
~~1.3~~	~~High Impact BES Cyber Systems and their associated:~~ ~~EACMS;~~ ~~PACS; and~~ ~~PCA~~ ~~Medium Impact BES Cyber Systems and their associated:~~ ~~EACMS;~~ ~~PACS; and~~ ~~PCA~~	~~For a change that deviates from the existing baseline configuration, update the baseline configuration as necessary within 30 calendar days of completing the change.~~	~~An example of evidence may include, but is not limited to, updated baseline documentation with a date that is within 30 calendar days of the date of the completion of the change.~~
~~1.4~~	~~High Impact BES Cyber Systems and their associated:~~ ~~1. EACMS;~~ ~~2. PACS; and~~ ~~3. PCA~~ ~~Medium Impact BES Cyber Systems and their associated:~~ ~~1. EACMS;~~ ~~2. PACS; and~~ ~~3. PCA~~	~~For a change that deviates from the existing baseline configuration:~~ ~~Prior to the change, determine required cyber security controls in CIP-005 and CIP-007 that could be impacted by the change;~~ ~~Following the change, verify that required cyber security controls determined in 1.4.1 are not adversely affected; and~~ ~~Document the results of the verification.~~	~~An example of evidence may include, but is not limited to, a list of cyber security controls verified or tested along with the dated test results.~~

1.25	High Impact BES Cyber Systems	Where technically feasible, fFor each change that deviates from the existing baseline implemented Secure Cconfiguration, perform the following, per system capability, except during CIP Exceptional Circumstances: 1.2.1. Prior to implementing any change in the production environment, test the changes in a test environment; or -test the changes test the changes in a production environment where the test is performed in a manner that minimizes adverse effects, that models the baseline Secure Cconfiguration to ensure that required cyber security controls in CIP-005 and CIP-007 are not adversely affected; and 1.2.22.3 Document the results of the testing and,- and, iif a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation	An example of evidence may include, but is not limited to, a list of tested cyber security controls, test dates, tested along with successful test results, and and a list of differences between the production and test environments including with descriptions of how any differences in the test and production environments were addressed.accounted for how any differences were accounted for., including of the date of the test.

CIP-010-~~4~~3 Table R1 – ~~Secure~~ Configuration ~~Change~~ Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
		between the test and production environments.	
1.~~3~~6	High Impact BES Cyber Systems Medium Impact BES Cyber Systems Note: Implementation does not require the Responsible Entity to renegotiate or abrogate existing contracts (including amendments to master agreements and purchase orders). Additionally, the following issues are beyond the scope of Part 1.~~3~~6: (1) the actual terms and conditions of a procurement contract; and (2) vendor performance and adherence to a contract.	Prior to a change that deviates from the existing ~~baseline~~ Secure C~~c~~onfiguration associated with installing or updating ~~baseline CIP-007-7 R2 and CIP-010-4 R3 Part 3~~operating system, firmware, and software~~.6secure configuration items in Parts 1.1.1, 1.1.2, and 1.1.5,~~ and when the method to do so is available to the Responsible Entity from the software source: 1.~~3~~6.1. Verify the identity of the software source; and 1.~~3~~6.2. Verify the integrity of the software obtained from the software source.	An example of evidence may include, but is not limited to a change request record that demonstrates the verification of identity of the software source and integrity of the software was performed prior to the ~~baseline~~ Secure Configuration change or a process which documents the mechanisms in place that would automatically ensure the identity of the software source and integrity of the software.

R2. Each Responsible Entity shall implement one or more documented process(es) to mitigate the risk posed by unauthorized change to Secure Configurations that collectively include each of the applicable requirement parts in *CIP-010-~~4~~3 Table R2 – Secure Configuration Monitoring.*

M2. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-~~4~~3 Table R2 – Secure Configuration Monitoring* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-010-~~3~~4 Table R2 – Secure Configuration ~~Monitoring~~			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PCS~~A~~	Use one or a combination of the following methods to monitor the implemented Secure Configuration (per system capability): ~~Monitor at least once every 35 calendar days for changes to the baseline configuration (as described in Requirement R1, Part 1.1). Document and investigate detected unauthorized changes.~~ • Hash monitoring; • Configuration monitoring; • Configuration auditing; or • Other method(s) to mitigate the risk posed by unauthorized change to Secure Configurations. The process requirements of Part 2.1 and timeline are based on the analysis of the risk to BES reliability and the impact rating of the applicable system(s).	An example of evidence may include, but is not limited to, logs from a system that is monitoring the configuration along with records of investigation for any unauthorized changes that were detected.
2.2	High Impact BES Cyber Systems and their associated:	Investigate and remediate detected unauthorized changes to the	An example of evidence may include, but is not limited to, records of

CIP-010-~~3~~4 Table R2 – Secure Configuration ~~Monitoring~~			
Part	**Applicable Systems**	**Requirements**	**Measures**
	1. EACS; and 2. PCS	implemented Secure Configuration found through implementation of Requirement R2 Part 2.1. The process requirements of Part 2.2 and timeline are based on the analysis of the risks to BES reliability and the risks posed by the detected unauthorized change to the implemented Secure Configuration	unauthorized change investigations and remediating activities.

R3. Each Responsible Entity shall implement one or more documented process(es) to mitigate the risk posed by system vulnerabilities that collectively include each of the applicable requirement parts in *CIP-010-~~3~~4 Table R3– Vulnerability ~~Assessments~~Management*.

M3. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-~~3~~4 Table R3 – Vulnerability ~~Assessments~~ Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-010-~~3~~4 Table R3 – Vulnerability ~~Assessments~~Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A	At least once every 15 calendar months, conduct a paper or active vulnerability assessment.	Examples of evidence may include, but are not limited to: • A document listing the date of the assessment (performed at least once every 15 calendar months), the controls assessed for each BES Cyber System along with the method of assessment; or • A document listing the date of the assessment and the output of any tools used to perform the assessment.

CIP-010-~~4~~3 Table R3 – Vulnerability ~~Assessments~~Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.2	High Impact BES Cyber Systems	~~Where technically feasible,~~ Per system capability, at least once every 36 calendar months: 3.2.1 Perform an active vulnerability assessment in a test environment, or perform an active vulnerability assessment in a production environment where the test is performed in a manner that minimizes adverse effects, that models the ~~baseline~~ Secure C~~c~~onfiguration of the BES Cyber System in a production environment; and 3.2.2 Document the results of the testing and, if a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation between the test and production environments.	An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed at least once every 36 calendar months), the output of the tools used to perform the assessment, and a list of differences between the production and test environments with descriptions of how any differences were accounted for in conducting the assessment.

CIP-010-~~3~~4 Table R3 – Vulnerability ~~Assessments~~Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PC~~S~~A	Prior to adding a new ~~applicable~~ Cyber Asset to a production environment, perform an active vulnerability assessment of the new Cyber Asset, except for CIP Exceptional Circumstances~~,~~ and like replacements and additions of the same type of Cyber Asset with a ~~baseline~~ Secure C~~c~~onfiguration that models an existing ~~baseline~~ Secure C~~c~~onfiguration of the previous or other existing Cyber Asset.	An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed prior to the commissioning of the~~-~~ addition~~new Cyber Asset~~) and the output of any tools used to perform the assessment.
3.4	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A	Document the results of the assessments conducted according to Parts 3.1, 3.2, and 3.3 and the action plan to remediate or mitigate vulnerabilities identified in the assessments including the planned date of completing the action plan and the execution status of any remediation or mitigation action items.	An example of evidence may include, but is not limited to, a document listing the results or the review or assessment, a list of action items, documented proposed dates of completion for the action plan, and records of the status of the action items (such as minutes of a status meeting, updates in a work order system, or a spreadsheet tracking the action items).

CIP-010-~~4~~3 Table R3 – Vulnerability ~~Assessments~~Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.5	High Impact BES Cyber Systems and their associated: 1. EACS; 2. PACS; and 3. PCS Medium Impact BES Cyber Systems and their associated: 1. EACS; 2. PACS; and 3. PCS	Identify software vulnerabilities using one or more of the following methods: • Vulnerability database monitoring; • Patch source monitoring; • Vulnerability scanning; or • Other method(s) to identify software vulnerabilities. The process of Part 3.5 shall include the periodicity for identifying software vulnerabilities based on the risk to BES reliability and the impact rating of the applicable system(s).	An example of evidence may include, but is not limited to: • Records of vulnerability database monitoring; • Records of patch source monitoring; or • Records of vulnerability scanning.

CIP-010-~~4~~3 Table R3 – Vulnerability ~~Assessments~~Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.6	High Impact BES Cyber Systems and their associated: 1. EACS; 2. PACS; and 3. PCS Medium Impact BES Cyber Systems and their associated: 1. EACS; 2. PACS; and 3. PCS	Create or update a plan to mitigate the identified software vulnerabilities from Part 3.5, through one or more of the following: • Implementing security patches; • Applying compensating controls; • System hardening; or • Other method(s) to mitigate software vulnerabilities. The plan for Part 3.6 must include the timeline for mitigating the software vulnerability based on the analysis of the risk posed by the software vulnerability to the applicable systems. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	An example of evidence may include, but is not limited to: • Records of implemented security patches; • Records of applied compensating controls; • Records of system hardening; or • Records of other methods.

R4. Each Responsible Entity, for its high impact and medium impact BES Cyber Systems and associated Protected Cyber ~~Assets~~Systems, shall implement, except under CIP Exceptional Circumstances, one or more documented plan(s) for Transient Cyber Assets and Removable Media that include the sections in Attachment 1.

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

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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.

- Each applicable entity shall retain evidence of each requirement in this standard for three calendar years.
- If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

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

D. Regional Variances

None.

E. Associated Documents

None.

Version History

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

Version	Date	Action	Change Tracking
			BES Cyber Systems.
2	1/21/16	FERC Order issued approving CIP-010-3. Docket No. RM15-14-000	
3	07/20/17	Modified to address certain directives in FERC Order No. 829.	Revised
3	08/10/17	Adopted by the NERC Board of Trustees.	

CIP-010-~~3~~4 - Attachment 1

Required Sections for Plans for Transient Cyber Assets and Removable Media

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

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

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

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

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

1.2.2. Locations, either individually or by group; and

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

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

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

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

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

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

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

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

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

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

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

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

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

Section 3. Removable Media

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

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

3.1.2. Locations, either individually or by group.

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

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

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

CIP-010-~~3~~4 - Attachment 2

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

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

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

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

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

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

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

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

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

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

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

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Periodic Review Team Preliminary Recommendation

FAC-008-3 Facility Ratings

Executive Summary

The Review Team completed a comprehensive review of FAC-008-3 – Facility Ratings. The team found the standard is sufficient to protect reliability and meets its reliability objective; however, there may be future opportunity to improve minor clarity and consistency issues. The observations and recommendations of the Review Team are documented below.

Introduction

The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every ten (10) years, or once every five (5) years for Reliability Standards approved by the American National Standards Institute (ANSI) as an American National Standard.[1] The Reliability Standard identified above has been included in the current cycle of periodic reviews. The Review Team shall consist of two (2) subgroups; a Standing Review Team, which is appointed annually by the Standards Committee (SC) for periodic reviews, and a stakeholder Subject Matter Expert (SME) team. Consistent with Section 13 of the Standards Processes Manual (SPM)[2], the SC may use a public nomination process to appoint the stakeholder Subject Matter Expert (SME) team, or may use another method to appoint that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. The technical experts provide the subject matter expertise and guide the development of the technical aspects of the periodic review, assisted by technical writers, legal and compliance experts. The technical experts maintain authority over the technical details of the periodic review.

Together, the Standing Review Team and SME stakeholder team are the Review Team for a particular periodic review project and complete their portion of the template below.

The purpose of the template is to collect background information, pose questions to guide a comprehensive review of the standard(s) by the Review Team, and document the Review Team's considerations and recommendations. The Review Team will post the completed template containing its recommendations for information and stakeholder input, as required by Section 13 of the NERC SPM.

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

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

Review Team Composition

	Standing Review Team	Plus Section 13 (SMEs):
Non-CIP Standards	Chairs of the following NERC Standing Committees[3]: • SC (Also the SC chair or his/her delegate from the SC will chair the Standing Review Team)[4] • Planning Committee • Operating Committee A regional representative will be included on the Standing Review Team. The Standing Review Team will meet with SMEs and help to ensure a consistent strategy and approach across all of the reviews.	The SC will appoint stakeholder SMEs for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to conduct its review of the standard(s) and complete the template below.
CIP Standards	Chairs of the following NERC Standing Committees[5]: • SC (Also the SC chair or his/her delegate from the SC will chair the Standing Review Team) • CIPC	The SC will appoint stakeholder SMEs for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to conduct its review of the standard(s) and complete the template below.

The Review Team will use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation from one of the following three (3) choices:

1. Recommend re-affirming the standard as steady-state (Green); or
2. Recommend that the standard is sufficient to protect reliability and meet the reliability objective of the standard; however there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor (Yellow); or

[3]Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.
[4] The Standards Committee chair may delegate one member of the SC to chair one Standing Review Team's review of a standard s), and another SC member to chair a review of another standard(s).
[5] Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

3. Recommend that the standard needs revision or retirement (Red).

If the team recommends a revision to, or a retirement of, the Reliability Standard, it must also submit a Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision or retirement.

A completed Periodic Review Template and any associated documentation should be submitted by email to Al McMeekin.

Applicable Reliability Standard: FAC-008-3 Facility Ratings
Team Members (include name and organization): 1. William Winters, Consolidated Edison Company of NY, Inc. 2. Josephine Daggett, Western Area Power Administration 3. Jeff Gruseck, Duke Energy 4. Kimberly Jursic, Georgia Power Company 5. Mario Kiresich, Southern California Edison 6. Hassib El Murdea, Ontario Power Generation 7. Brett Riedl, ComEd 8. Yaoyu Wang, American Electric Power
Date Review Completed:

Background Information *(to be completed initially by NERC staff)*

1. Are there any outstanding Federal Energy Regulatory Commission (FERC) directives associated with the Reliability Standard? (*If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)*

   ☐ Yes
   ☒ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an (outstanding, in progress, or approved) Interpretation or Compliance Application Notice (CAN)? (*If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or other stakeholder-identified issue(s) that apply to the Reliability Standard*.)

   ☐ Yes
   ☒ No

   Please explain:

3. Is the Reliability Standard one of the most violated Reliability Standards?

☐ Yes
☒ No

If so, does the cause of the frequent violation appear to be a lack of clarity in the language?

☐ Yes
☐ No

Please explain:

Questions for the Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff, as indicated in the Background questions above. Either as a guide to help answer the ensuing questions or as a final check, the Review Team is to use Attachment 3: Independent Expert Evaluation Process.

I. Quality

1. **Reliability Need, Paragraph 81:** Do any of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? *Use Attachment 2: Paragraph 81 Criteria to make this determination.*

   ☐ Yes
   ☒ No

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

2. **Clarity:** From the Background Information section of this template, has the Reliability Standard been the subject of an Interpretation, CAN or issue associated with it, or is frequently violated because of ambiguity?

   a. Does the Reliability Standard have obvious ambiguous language?

   b. Does the Reliability Standard have language that requires performance that is not measurable?

   c. Are the requirements consistent with the purpose of the Reliability Standard?

   d. Should the requirements stand alone as is, or should they be consolidated with other standards?

   e. Is the Reliability Standard complete and self-contained?

   f. Does the Reliability Standard use consistent terminology?

   ☐ Yes
   ☒ No

   Please summarize your assessment: **See Attachment 4.**

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

   ☐ Yes
   ☒ No

   Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, Violation Risk Factors (VRF), Violation Severity Levels (VSL) and Time Horizons) consistent with the direction of the Reliability Assurance Initiative (RAI) and FERC and NERC guidelines?

   ☒ Yes
   ☐ No

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

   See Attachment 4.

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

   ☐ Yes
   ☒ No

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

   See Attachment 4.

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions or other factors?

   ☐ Yes
   ☒ No

   If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

7. **Practicable**:
   a. Can the Reliability Standard be practically implemented?

      ☒ Yes
      ☐ No

   b. Is there a concern that it is not cost effective as drafted?

      ☐ Yes
      ☒ No

   Please summarize your assessment of the practicability of the standard:

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

   ☒ Yes
   ☐ No

Guiding Questions:

a. If the Reliability Standard is applicable to Generator Owners (GOs) and/or Generator Operators (GOPs), is there any ambiguity about the inclusion of generator Interconnection Facilities? (If generation Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

Response: The standard is applicable to GOs. There is no ambiguity about the inclusion of generator Interconnection Facilities.

b. If the Reliability Standard is not applicable to GOs and/or GOPs, is there a reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard? (If so, GOs that own and/or GOPs that operate relevant generator Interconnection Facilities should be explicit in the Applicability section of the Reliability Standard.)

Response: Not applicable.

c. If the Reliability Standard is applicable to Transmission Operators (TOPs) and/or Distribution Providers (DPs), is there any ambiguity about the inclusion of Transmission Interconnection Facilities? (If Transmission Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

Response: Not applicable.

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

☒ Yes
☐ No

If not, please summarize your assessment:

Guiding Questions:

a. Does the Reliability Standard address performance, risk (prevention) and capability?

☒ Yes
☐ No

b. Does the Reliability Standard follow the RBS format (for example, requirement and part structure) in Attachment 1?

☐ Yes
☒ No

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

☒ Yes
☐ No

[6] Ten Benchmarks of an Excellent Reliability Standard, posted at Page 626 of: http://www.nerc.com/pa/Stand/Resources/Documents/DT_Reference_Manual_Resource_Package_080114.pdf

II. Content

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

☒ Yes
☐ No

If not, please summarize your assessment: **See Attachment 4.**

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

☒ Yes
☐ No

If not, please summarize your assessment:
Applicability: Is there a technical justification for revising the Applicability of the Reliability Standard, or specific requirements within the standard, to account for differences in reliability risk?

☐ Yes
☒ No

If so, please summarize your assessment:

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

☐ Yes
☒ No

If a gap is identified, please explain:

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

☒ Yes
☐ No

If not, please summarize your assessment:

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

☒ Yes
☐ No

If not, please summarize your assessment:

15. **Related Regional Reliability Standards**: Is there a related regional Reliability Standard, and is it appropriate to recommend the regional Reliability Standard be retired, appended into the continent-wide standard, or revised in favor of a continent-wide standard?

☐ Yes
☒ No

If yes, please identify the regional standard(s) and summarize your assessment:

Red, Yellow, Green Grading

Using the questions above, the Review Team shall come to a consensus on whether the Reliability Standard is Green – i.e., affirm as steady-state; Yellow – is sufficient to protect reliability and meet the reliability objective of the standard, however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor; or Red - either retire or needs revision, and, thus, a SAR should be developed to process the standard through the standards development process for retirement or revision. The reasons for the Review Team's conclusions of Green, Yellow, or Red shall be documented. If a consensus is not reached within the Review Team, minority reviews shall be posted for stakeholder comment, along with the majority opinion on whether the Reliability Standard is Green, Yellow, or Red.

Recommendation

The answers to the questions above, along with its Red, Yellow, or Green grading and the recommendation of the Review Team, will be posted for a 45-day comment period, and the comments publicly posted. The Review Team will review the comments to evaluate whether to modify its initial recommendation, and will document the final recommendation which will be presented to the SC.

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

☐ RE-AFFIRM *(This should be checked only if there are no outstanding directives, Interpretations or issues identified by stakeholders.) GREEN*

☒ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard; however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☐ RETIRE (Would include retirement of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Preliminary Recommendation posted for industry comment *(date):* 10/30/2017

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

☐ RE-AFFIRM *(This should be checked only if there are no outstanding directives, Interpretations or issues identified by stakeholders.) GREEN*

☐ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard; however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☐ RETIRE (Would include retirement of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR must be included and the technical justification included in the SAR)*:

Date submitted to Standards Committee:

Attachment 1: Results-based Standards

Question 9 for the Review Team asks if the Reliability Standard is results-based. The information below will be used by the Review Team in making this determination.

Transitioning the current body of standards into a clear, concise, and effective body will require a comprehensive application of the RBS concept. RBS concepts employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures, and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

Accordingly, the Review Team shall consider whether the Reliability Standard contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved. The RBS concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff and the Review Team should recommend that the Reliability Standard be revised or reformatted in accordance with the RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[7] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Periodic Review Template.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion); and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

B2. Data Collection/Data Retention

These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

[7] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation

The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect reliability of the bulk power system.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting

The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates

The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice

The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant

The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with

little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the periodic review. The exception would be a requirement, such as the Critical Information Protection (CIP) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?

The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (*footnote omitted*)

C6. Is there any negative impact on the defense in depth protection of the BES?

The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?

The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Attachment 3: Independent Expert Evaluation Process

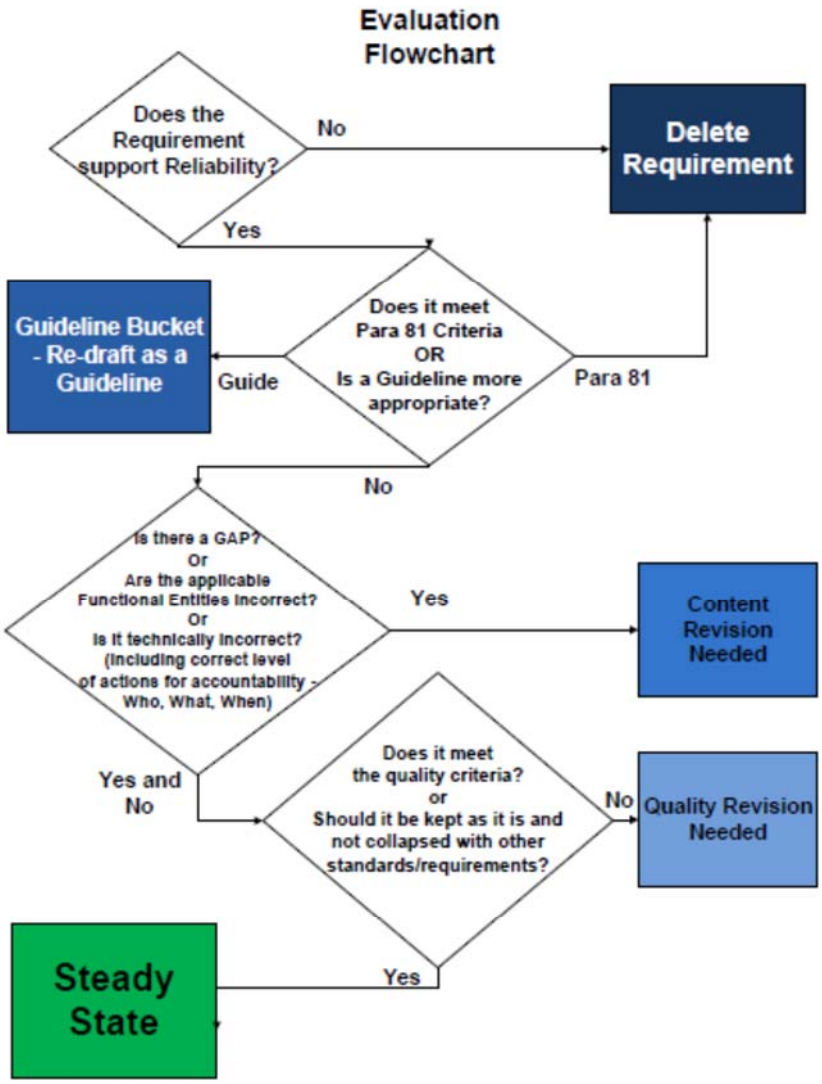


Figure 1: Evaluation Flow Chart

Attachment 4: Potential Revisions/Corrections

The Review Team consolidated a number of potential improvements that could be implemented by a drafting team should the standard be opened for revision. If you provide comments during the posting period regarding one of the team's observations, please reference the particular observation.

1) Paragraph 81 (None)

2) Clarity

   A. Requirement R1 and Requirement R2:
   Future consideration could be given to combining the requirements. The provision for Generator Owners to use documentation (e.g., design criteria or test data) for establishing Facility Ratings could be incorporated into the Facility Ratings methodology specified in Requirement R2.

   B. Requirement R2 and Requirement R3:
   Consider reordering the Parts of Requirements R2 and R3 in a more logical order, perhaps hierarchically from Facility Ratings to Equipment Ratings.

   C. Requirement R2, Part 2.1 and Requirement R3, Part 3.1:
   Consider replacing the term 'methodology' in Requirement R2, Part 2.1 and Requirement R3, Part 3.1 with the term 'methods' to prevent confusion. Using the term 'methodology' twice implies that two different documents (rather than a single document for Facility Ratings) are required.

   D. Requirement R2, Part 2.2 and Requirement R3, Part 3.2:
   Consider removing the word 'methods' as the 'methodology' is already addressed in Requirement R2, Part 2.1 and Requirement R3, Part 3.1. Parts 2.2 and 3.2 should be limited to the assumptions and design criteria.

   E. Requirement R2, Part 2.2.1 and Requirement R3, Part 3.2.1:
   Consider revising Parts 2.2.1 and 3.2.1 to state: "Industry standard(s) for establishing Equipment Ratings" since 'methodology' is already addressed in Parts 2.1 and 3.1.

   F. Requirement R2, Part 2.4 and Requirement R3, Part 3.4:
   Consider deleting the main body of Parts 2.4 and 3.4 as they seem redundant to Parts 2.1 and 3.1, respectively. Parts 2.4.1, 2.4.2, 3.4.1 and 3.4.2 are sufficiently independent and clear enough to be Parts 2.4, 2.5, 3.4, and 3.5, respectively.

   G. Requirement R7 and Requirement R8, Part 8.1:
   Consider replacing 'as scheduled by … requesting entities' with "on a mutually agreed upon schedule". According to the current language, a requesting entity could propose an unreasonable schedule which could impose a compliance burden on the provider.

3) Definitions (None)

4) Compliance Elements

   A. High VSLs Requirements R2 and R3:

Since Requirements R2 and R3 are identical, consider revising the language of the High VSLs to be identical.

5) Consistency with other Reliability Standards

   A. Requirement R1, Part 1.1:
   Consider adding the term 'Facility(ies)' after 'generator' to be consistent with the term 'Generator Facility(ies)' in the main body of Requirement R1.

   B. Requirement R1, Part 1.1, Requirement R2, Part 2.1, Requirement R3, Part 3.1:
   Consider making the language (of the three bullets) referencing industry groups (e.g. IEEE, ANSI, CIGRE) consistent across all requirements.

   C. Requirement R1, Part 1.2, Requirement R2, Part 2.3, Requirement R3, Part 3.3:
   Consider using "do not exceed" rather than "respect" for consistency and additional clarity.

   D. Requirement R2, Part 2.1 and Requirement R3, Part 3.1:
   Consider using the NERC Glossary term "Equipment Ratings" rather than "Ratings of the equipment that comprise the Facility".

   E. Measures M4 and M5:
   Update the text "(Retirement approved by NERC BOT pending applicable regulatory approval.)" to reflect FERC approval of retirement as stated with Requirements R4 and R5: "(Retirement approved by FERC effective January 21, 2014.)"

6) Changes Technology, System Conditions, or other Factors (None)

7) Practicable (None)

8) Consideration of Generator and Transmission Interconnection Facilities (None)

9) Results-Based Standard (RBS) (None)

10) Technical accuracy

   A. Requirement R2, Part 2.4 and Requirement R3, Part 3.4:
   Consider removing 'shunt compensation devices' from the list of equipment that comprises a Facility. Shunt devices are not series-connected devices. There are no thermal ratings and therefore are not considered in the Facility Rating as limiting equipment. The RSAW correctly focuses the auditor's attention on series-connected devices.

11) Functional Model (None)

12) Applicability (None)

13) Reliability Gaps (None)

14) Technical Quality (None)

15) Does the Reliability Standard reflect a higher solution than the lowest common denominator? (None)

16) Related Regional Reliability Standards (None)

Standard Authorization Request (SAR) Form

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Standards Alignment with Registration		
Date Submitted:			
SAR Requester			
Name:	Revised by Project 2017-07 Standards Alignment with Registration SAR Drafting Team Stephen Wendling, Chair		
Organization:	American Transmission Company		
Telephone:	(608) 877-8232	Email:	swendling@atcllc.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
This project will align the Reliability Standards with the outcome of the Risk-Based Registration (RBR) initiative.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
This project would modify Reliability Standards to be consistent with the FERC-approved changes to registration as part of the RBR initiative.			
Project Scope (Define the parameters of the proposed project):			
This project will review and align Reliability Standards impacted by the RBR initiative.			
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):			
This project will formally address any remaining edits to the Reliability Standards that are needed to align the existing standards with the RBR initiatives. The edits include updates to the BAL, CIP, FAC, INT, IRO, MOD, NUC, and TOP family of standards to remove the references to Purchasing-Selling Entities			

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
(PSEs) and Interchange Authorities (IAs); references to the Load-Serving Entity (LSEs) will be removed or replaced by ~~either the Distribution Provider (DP), the Balancing Authority (BA), or~~ the appropriate functional ~~applicable~~ entity. ~~Additionally, t~~The project will include adding Underfrequency Load Shedding (UFLS)-only Distribution Providers (DPs) to the Applicability ~~Section~~ section of PRC-005 and PRC-006 per NERC registration criteria.~~; and review the Applicability sections of PRC-004 and PRC-008 and revise, as appropriate, to add UFLS-only DPs.~~ Additionally, the project will consider whether to include a definition for UFLS into the NERC Glossary of Terms, as well as review the standards to ensure consistent use of the term Planning Coordinator. The clean-up effort of the standards can be categorized into the following: 1. Modifications to existing standards where the removal of the retired function may need replacement by another function. For instance, Reliability Standard MOD-032-1 specifies certain data from LSEs that may need to be provided by other functional entities going forward. 2. Modifications where the applicable entity and references may be removed. These updates may be able to follow a similar process to the Paragraph 81 initiatives where standards are redlined and posted for industry comment and ballot. A majority of the edits would simply remove deregistered functional entities and their applicable requirements/references. The impacted standards include the BAL, CIP, IRO, and TOP family of standards. Additionally, PRC-005~~-1.1b~~ and PRC-006~~-003~~ will be updated to add UFLS-only DP to the Applicability ~~Sections~~sections. ~~and a review of the Applicability Sections of PRC-004-5(i) and PRC-008-0 to add, as appropriate, UFLS-only DP to align with the post-RBR registration impacts.~~ 3. Initiatives that can address RBR updates through the periodic review process. ~~-~~The 2017-07 SAR drafting team should consider whether it or the periodic review teams currently reviewing those standards should make the necessary revisions. ~~This would include the INT-004-3.1 and NUC-001-3 standards. Rather than the Project 2017-07 making the revisions the SDT could coordinate with the periodic review teams currently reviewing INT-004-3.1 and NUC-001-3 so that any changes resulting from those periodic reviews, if any, may be proposed at the same time after completion of each periodic review.~~
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
No additional costs outside of the time and resources needed to serve on the SAR and Standard Drafting Team.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.* Dispersed Generation Resources):
None
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.* Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):

Requested information
Since LSE is being removed or replaced by either the Distribution Provider (DP), the Balancing Authority (BA), or the appropriate Applicable Entity for the standards that need to be updated, those entities will likely be best suited for the MOD and PRC updates.
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
None
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.
☐	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

[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.

Market Interface Principles	
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
NPCC and SERC	~~UFLS-only DP will be added to the Applicability Section of PRC-006 and will create a variance of the following two~~ Regional Reliability Standards: PRC-006-NPCC-1 PRC-006-SERC-01 PRC-006-SERC-02

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	~~January X~~December 11, 2017	Standards Information Staff	Revised
3	February 1, 2018	Standards Information Staff	Revised

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

45-day formal comment period with initial ballot

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	06/13/18
SAR posted for comment	03/30/18 – 04/30/18
28-day informal comment period	08/10/18 – 09/06/18

Anticipated Actions	Date
45-day formal or informal comment period with initial ballot	October 2018 – November 2018
45-day formal or informal comment period with additional ballot	TBD
10-day final ballot	TBD
Board adoption	February 2019

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

A. Introduction

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events

2. **Number:** TPL-007-~~2~~3

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-~~2~~3.

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.

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 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. *[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 in Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be revised if situations beyond the control of the responsible entity determined in Requirement R1 prevent implementation of the CAP within the timetable for implementation provided in Part 7.3. The revised CAP shall document the following, and be updated at least once every 12 calendar months until implemented:

7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1;

7.4.2. Description of the original CAP, and any previous changes to the CAP, with the associated timetable(s) for implementing the selected actions in Part 7.1; and

7.4.3. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable, and the updated timetable for implementing the selected actions.

7.5. 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 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 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, 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. 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. 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: (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.

GMD Measurement Data Processes

R11. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement R11.

R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator's planning area in accordance with Requirement R12.

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, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.
- For Requirements R11 and R12, each responsible entity shall retain documentation as evidence for three years.

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 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 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 three of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy four of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more

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.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System Model.
R12.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

D. Regional Variances

D.A. Regional Variance for Canadian Jurisdictions

This Variance shall be applicable in Canada.

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 with the following:

D.A.7.3. Include a timetable, subject to revision by the responsible entity in Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

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.

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.

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.

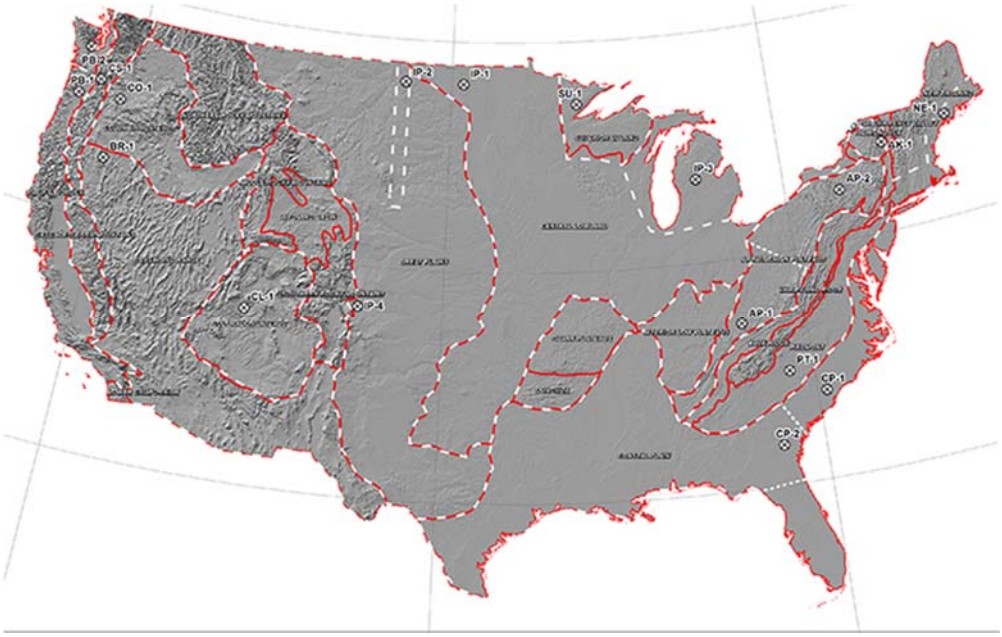


Figure 1: Physiographic Regions of the Continental United States[6]



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

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.

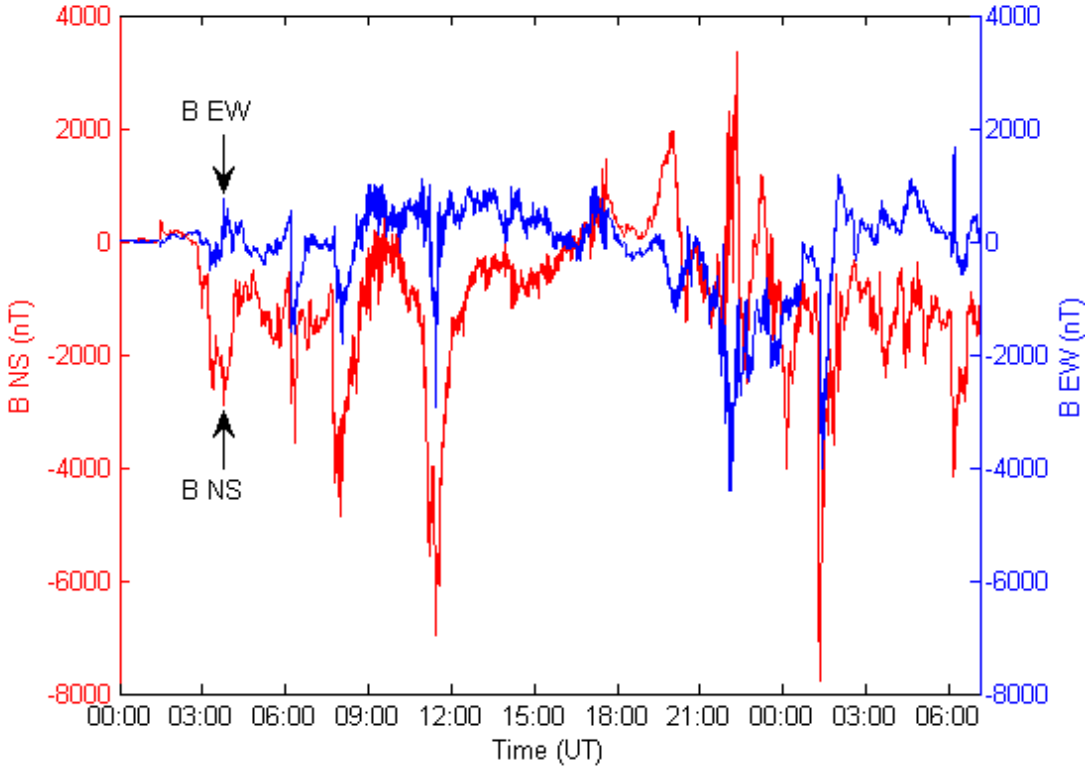


Figure 3: Benchmark Geomagnetic Field Waveform
Red B_n (Northward), Blue B_e (Eastward)

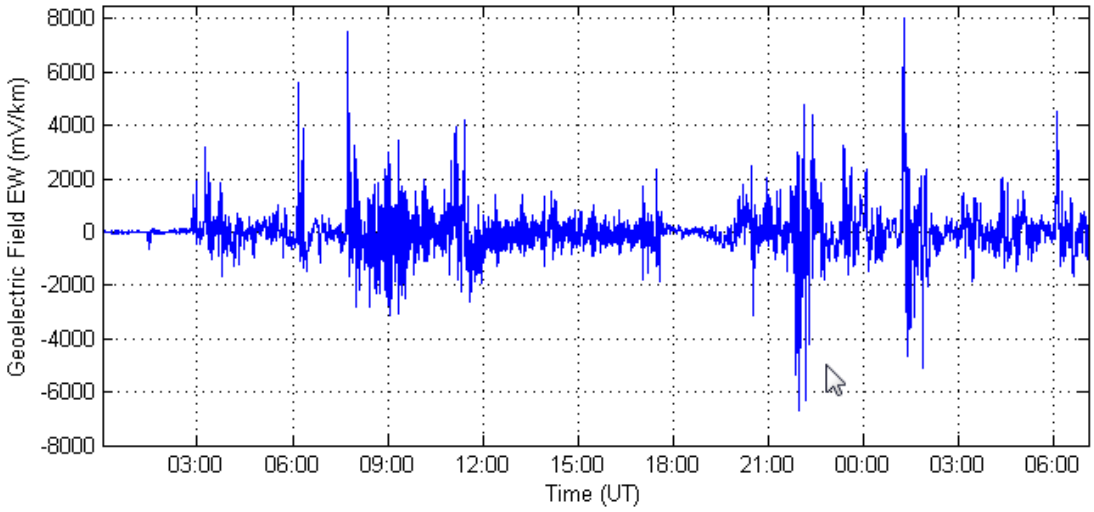


Figure 4: Benchmark Geoelectric Field Waveform
E_E (Eastward)

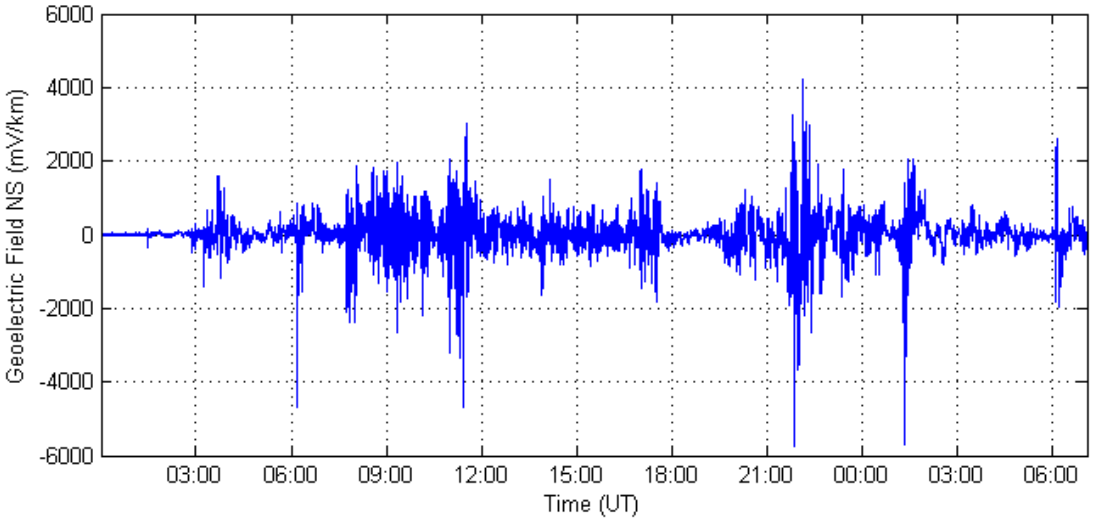


Figure 5: Benchmark Geoelectric Field Waveform
E_N (Northward)

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.

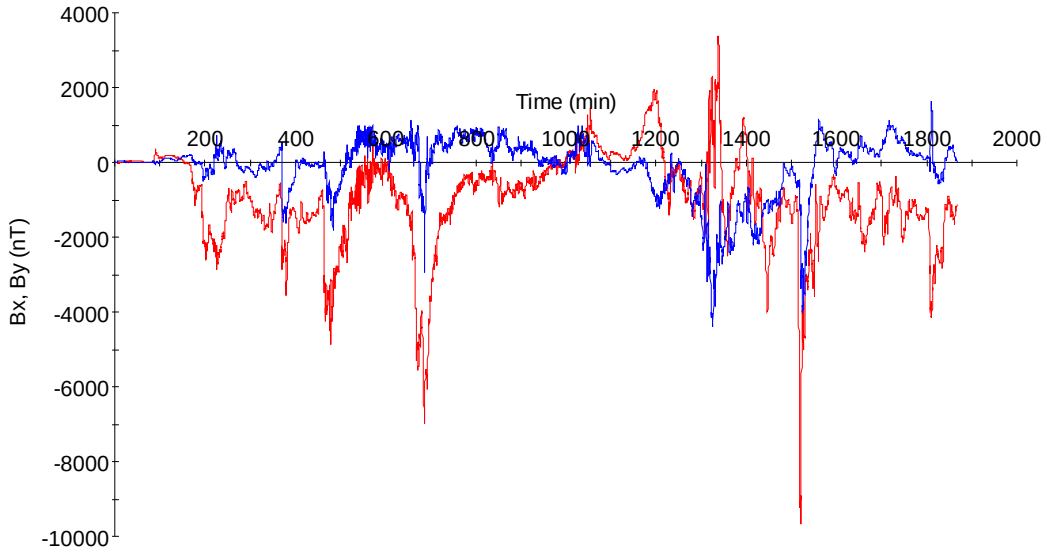


Figure 6: Supplemental Geomagnetic Field Waveform
Red B_N (Northward), Blue B_E (Eastward)

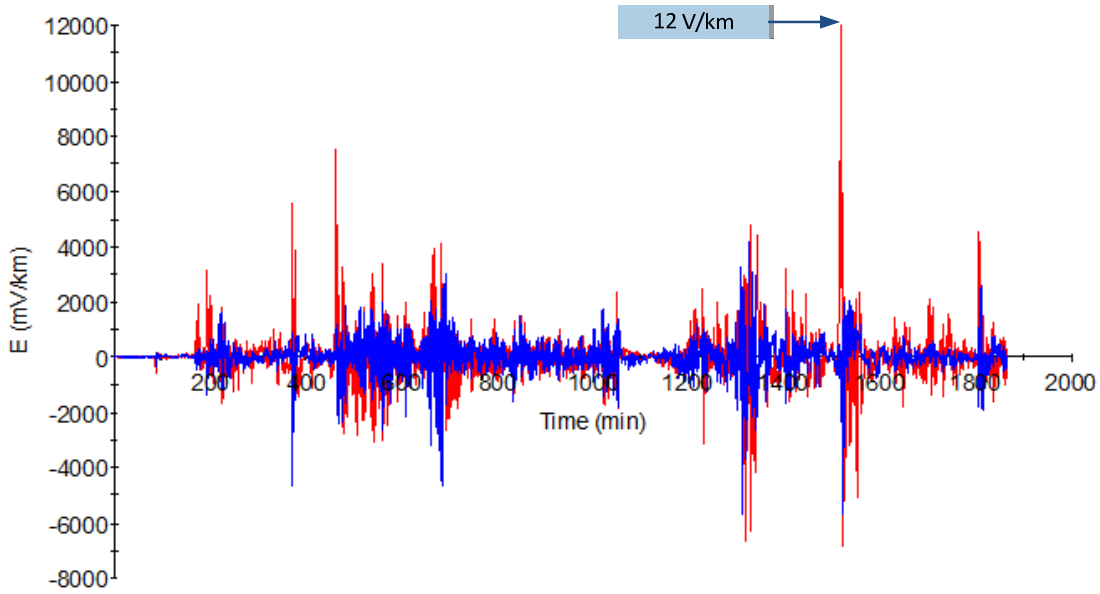


Figure 7: Supplemental Geoelectric Field Waveform
Blue E_N (Northward), Red E_E (Eastward)

Attachment 1-CAN

Attachment 1-CAN provides an alternative that any 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] 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).

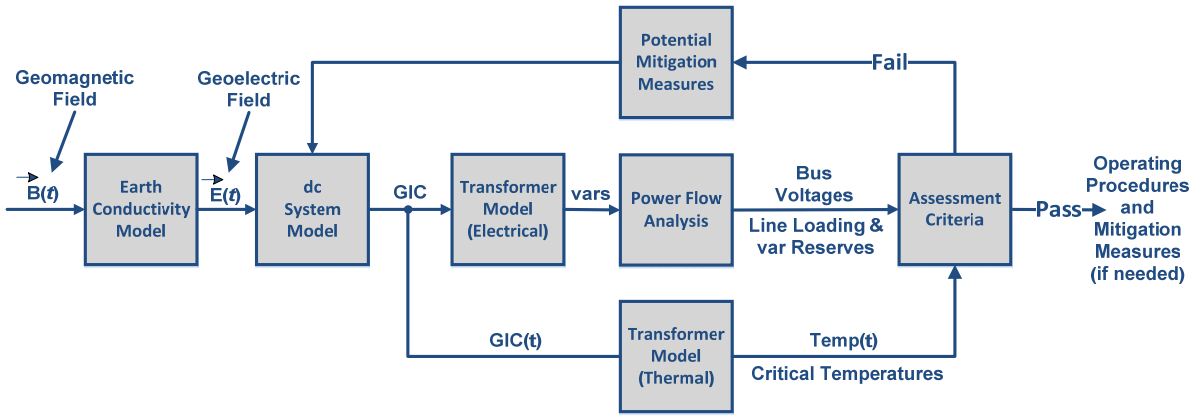
For the benchmark GMD Vulnerability Assessment(s), an entity shall consider the large-scale spatial structure of the GMD event. For the supplemental GMD Vulnerability Assessment(s), an

[1] The "earth transfer function" is the relationship between the electric fields and magnetic field variations at the surface of the earth.

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: *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

[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.
[13] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf.

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 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.

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[14] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.
[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.

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 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

[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.
[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.

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 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

[22] http://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-007-1_Transformer_Thermal_Impact_Assessment_White_Paper.pdf.
[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.

studies may provide more useful information for validation and situational awareness purposes. Conversely, data from GIC monitors that are located in the vicinity of transportation systems using direct current (e.g., subways or light rail) may be unreliable.

- **Monitor specifications.** Capabilities of Hall effect transducers, existing and planned, should be considered in the operating process. When planning new GIC monitor installations, consider monitor data range (e.g., -500 A through + 500 A) and ambient temperature ratings consistent with temperatures in the region in which the monitor will be installed.

- **Sampling Interval.** An entity's operating process may be constrained by capabilities of existing GIC monitors. However, when possible specify data sampling during periods of interest at a rate of 10 seconds or faster.

- **Collection Periods.** The process should specify when the entity expects GIC data to be collected. For example, collection could be required during periods where the Kp index is above a threshold, or when GIC values are above a threshold. Determining when to discontinue collecting GIC data should also be specified to maintain consistency in data collection.

- **Data format.** Specify time and value formats. For example, Greenwich Mean Time (GMT) (MM/DD/YYYY HH:MM:SS) and GIC Value (Ampere). Positive (+) and negative (-) signs indicate direction of GIC flow. Positive reference is flow from ground into transformer neutral. Time fields should indicate the sampled time rather than system or SCADA time if supported by the GIC monitor system.

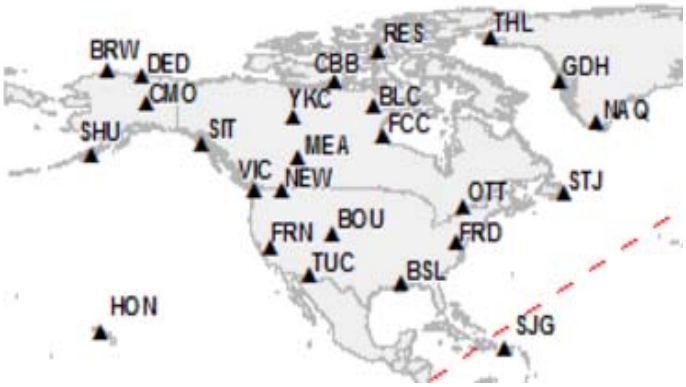
- **Data retention.** The entity's process should specify data retention periods, for example 1 year. Data retention periods should be adequately long to support availability for the entity's model validation process and external reporting requirements, if any.

- **Additional information.** The entity's process should specify collection of other information necessary for making the data useful, for example monitor location and type of neutral connection (e.g., three-phase or single-phase).

Requirement R12

Magnetometers measure changes in the earth's magnetic field. Entities should obtain data from the nearest accessible magnetometer. Sources of magnetometer data include:

- Observatories such as those operated by U.S. Geological Survey and Natural Resources Canada, see figure below for locations:[26]



- Research institutions and academic universities;
- Entities with installed magnetometers.

Entities that choose to install magnetometers should consider equipment specifications and data format protocols contained in the latest version of the *INTERMAGNET Technical Reference Manual*, Version 4.6, 2012.[27]

[26] http://www.intermagnet.org/index-eng.php.
[27] http://www.intermagnet.org/publications/intermag_4-6.pdf.

Rationale

During development of TPL-007-1, text boxes were embedded within the standard to explain the rationale for various parts of the standard. The text from the rationale text boxes was moved to this section upon approval of TPL-007-1 by the NERC Board of Trustees. In developing TPL-007-2, the SDT has made changes to the sections below only when necessary for clarity. Changes are marked with brackets [ ].

Rationale for Applicability:

Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these transformers are not included in the applicability for this standard.

Terminal voltage describes line-to-line voltage.

Rationale for R1:

In some areas, planning entities may determine that the most effective approach to conduct a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

Rationale for R2:

A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model is provided in the *Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System*,[28] December 2013, developed by the NERC GMD Task Force.

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformer(s) due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include, for example, recalling or postponing maintenance outages.

The Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1, which is proposed for revision in the NERC filing dated August 29, 2014 (Docket No. RM12-1-000). NERC guidelines require consistency among Reliability Standards.

[28] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf.

Rationale for R3:

Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1. Steady state voltage limits are an example of System steady state performance criteria.

Rationale for R4:

The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The *Geomagnetic Disturbance Planning Guide*,[29] December 2013 developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. The provision of information in Requirement R4, Part 4.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R5:

This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment.

GIC(t) provided in Part 5.2 can alternatively be used to convert the steady state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the *Transformer Thermal Impact Assessment White Paper*,[30] October 2017.

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

[29] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.
[30] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1.

The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R6:

The transformer thermal impact screening criterion has been revised from 15 A per phase to 75 A per phase [for the benchmark GMD event]. Only those transformers that experience an effective GIC value of 75 A per phase or greater require evaluation in Requirement R6. The justification is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*,[31] October 2017.

The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment White Paper*,[32] October 2017.

Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

The provision of information in Requirement R6, Part 6.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R7:

The proposed requirement addresses directives in Order No. 830 for establishing Corrective Action Plan (CAP) deadlines associated with GMD Vulnerability Assessments. In Order No. 830, FERC directed revisions to TPL-007 such that CAPs are developed within one year from the completion of GMD Vulnerability Assessments (P 101). Furthermore, FERC directed establishment of implementation deadlines after the completion of the CAP as follows (P 102):

- Two years for non-hardware mitigation; and
- Four years for hardware mitigation.

The objective of Part 7.4 is to provide awareness to potentially impacted entities when implementation of planned mitigation is not achievable within the deadlines established in Part

[31] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.
[32] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

7.3. Examples of situations beyond the control of the of the responsible entity (see Section 7.4) 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.

Rationale for Table 3:

Table 3 has been revised to use the same ground model designation, FL1, as is being used by USGS. The calculated scaling factor for FL1 is 0.74. [The scaling factor associated with the benchmark GMD event for the Florida earth model (FL1) has been updated to 0.76 in TPL-007-2 based on the earth model published on the USGS public website.]

Rationale for R8 – R10:

The proposed requirements address directives in Order No. 830 for revising the benchmark GMD event used in GMD Vulnerability Assessments (P 44, P 47-49). The requirements add a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for localized peak geoelectric fields.

Rationale for R11 – R12:

The proposed requirements address directives in Order No. 830 for requiring responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness (P 88; P. 90-92). GMD measurement data refers to GIC monitor data and geomagnetic field data in Requirements R11 and R12, respectively. See the Guidelines and Technical Basis section of this standard for technical information.

The objective of Requirement R11 is for entities to obtain GIC data for the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model to inform GMD Vulnerability Assessments. Technical considerations for GIC monitoring are contained in Chapter 9 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System* (NERC 2012 GMD Report). GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the transformer and measure dc current flowing through the neutral.

The objective of Requirement R12 is for entities to obtain geomagnetic field data for the Planning Coordinator's planning area to inform GMD Vulnerability Assessments. Magnetometers provide geomagnetic field data by measuring changes in the earth's magnetic field. Sources of geomagnetic field data include:

- Observatories such as those operated by U.S. Geological Survey, Natural Resources Canada, research organizations, or university research facilities;
- Installed magnetometers; 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.

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

45-day formal comment period with initial ballot

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	06/13/18
SAR posted for comment	03/30/18 – 04/30/18
28-day informal comment period	08/10/18 – 09/06/18

Anticipated Actions	Date
45-day formal or informal comment period with initial ballot	October 2018 – November 2018
45-day formal or informal comment period with additional ballot	TBD
10-day final ballot	TBD
Board adoption	February 2019

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

A. Introduction

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events

2. **Number:** TPL-007-3

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.

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.

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 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. *[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 in Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be revised if situations beyond the control of the responsible entity determined in Requirement R1 prevent implementation of the CAP within the timetable for implementation provided in Part 7.3. The revised CAP shall document the following, and be updated at least once every 12 calendar months until implemented:

7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1;

7.4.2. Description of the original CAP, and any previous changes to the CAP, with the associated timetable(s) for implementing the selected actions in Part 7.1; and

7.4.3. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable, and the updated timetable for implementing the selected actions.

7.5. 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 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 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, 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. 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. 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: (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.

GMD Measurement Data Processes

R11. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement R11.

R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator's planning area in accordance with Requirement R12.

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, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.
- For Requirements R11 and R12, each responsible entity shall retain documentation as evidence for three years.

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 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 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 three of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy four of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more

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.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System Model.
R12.	N/A	N/A	N/A	The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

D. Regional Variances

D.A. Regional Variance for Canadian Jurisdictions

This Variance shall be applicable in Canada.

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 with the following:

D.A.7.3. Include a timetable, subject to revision by the responsible entity in Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

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.

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.

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.

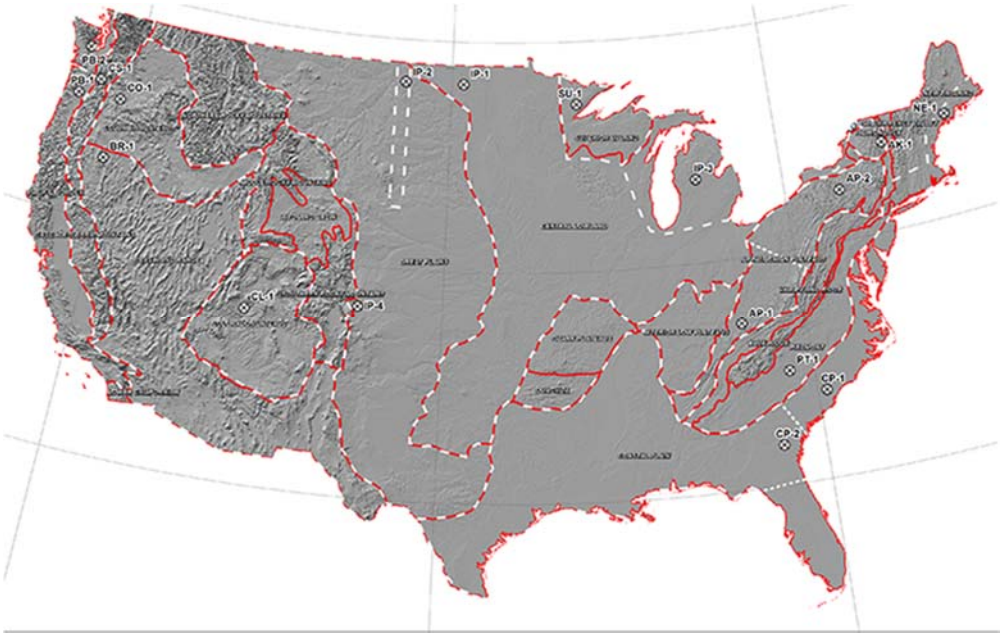


Figure 1: Physiographic Regions of the Continental United States[6]



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

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.

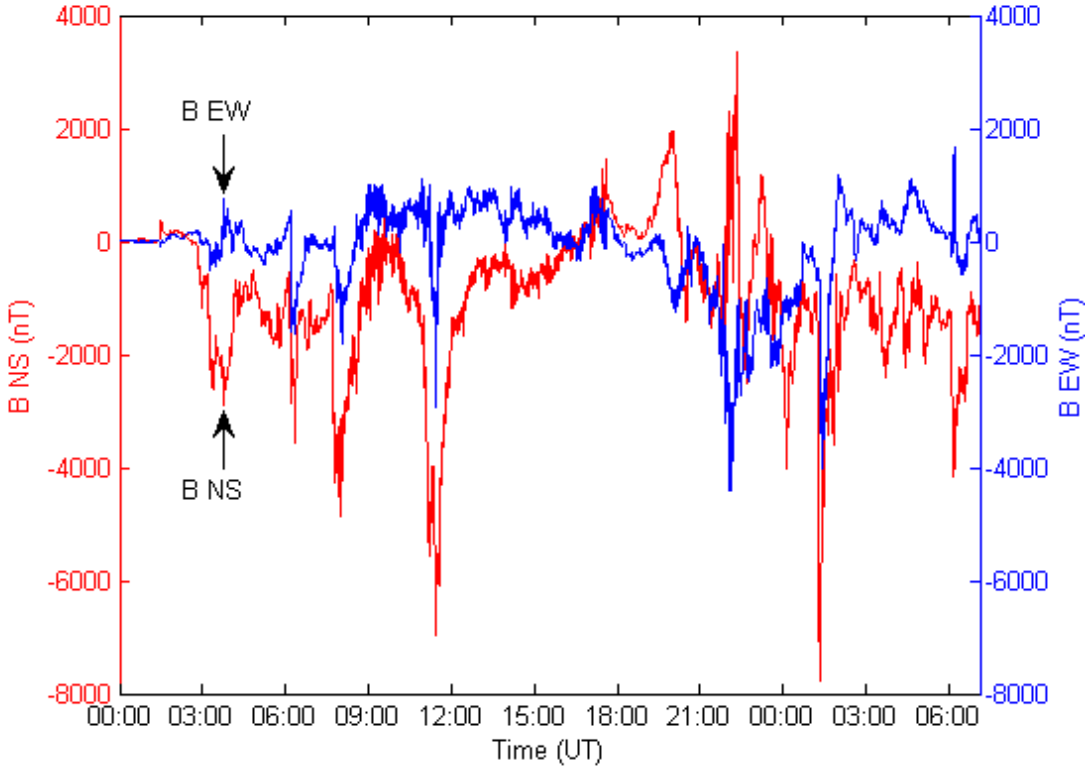


Figure 3: Benchmark Geomagnetic Field Waveform
Red B_n (Northward), Blue B_e (Eastward)

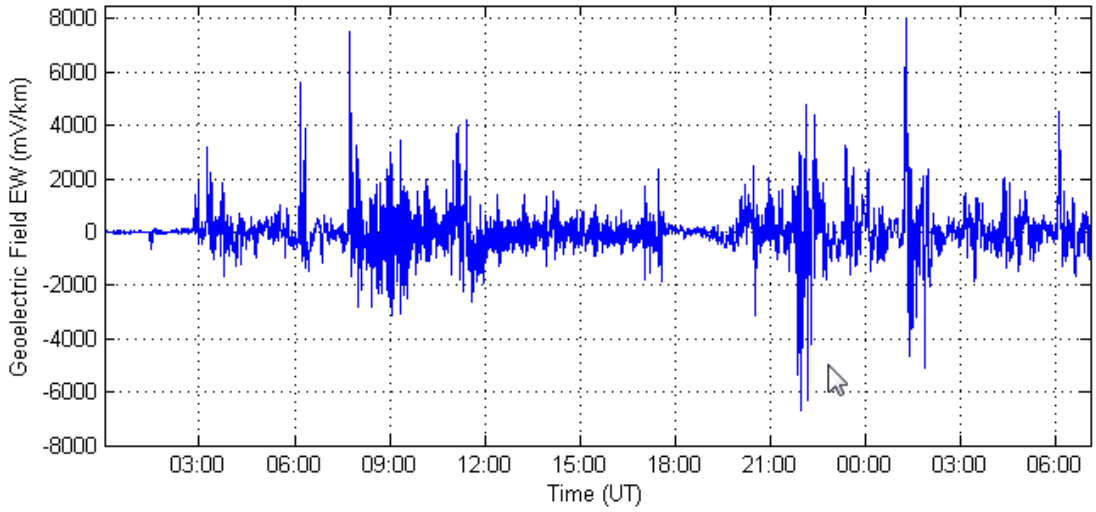


Figure 4: Benchmark Geoelectric Field Waveform
E_E (Eastward)

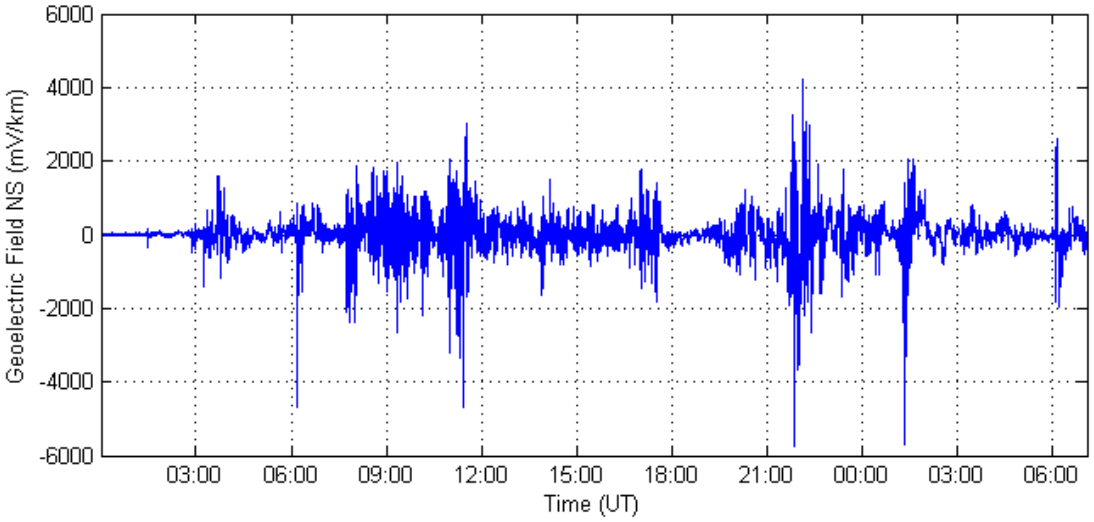


Figure 5: Benchmark Geoelectric Field Waveform
E_N (Northward)

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.

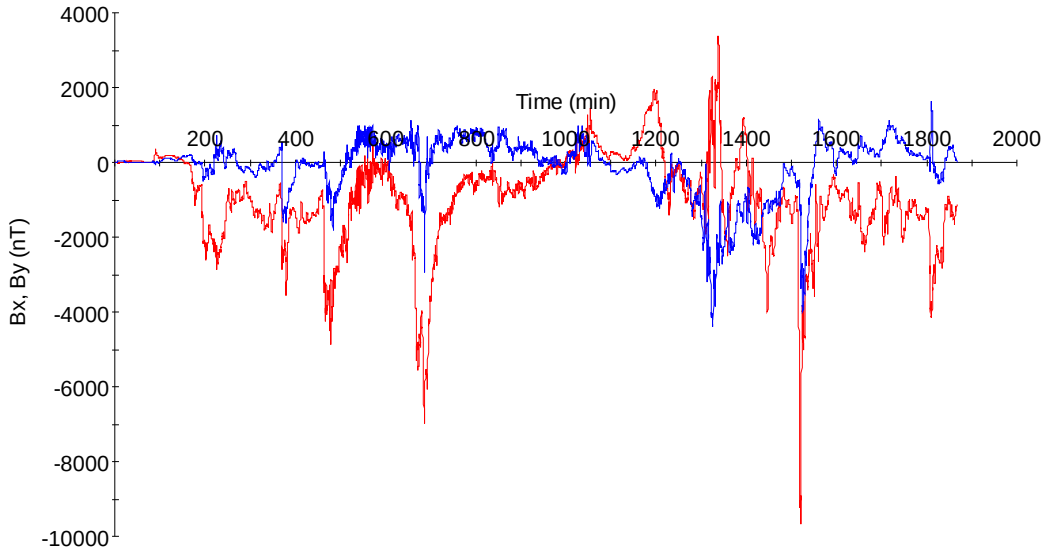


Figure 6: Supplemental Geomagnetic Field Waveform
Red B_N (Northward), Blue B_E (Eastward)

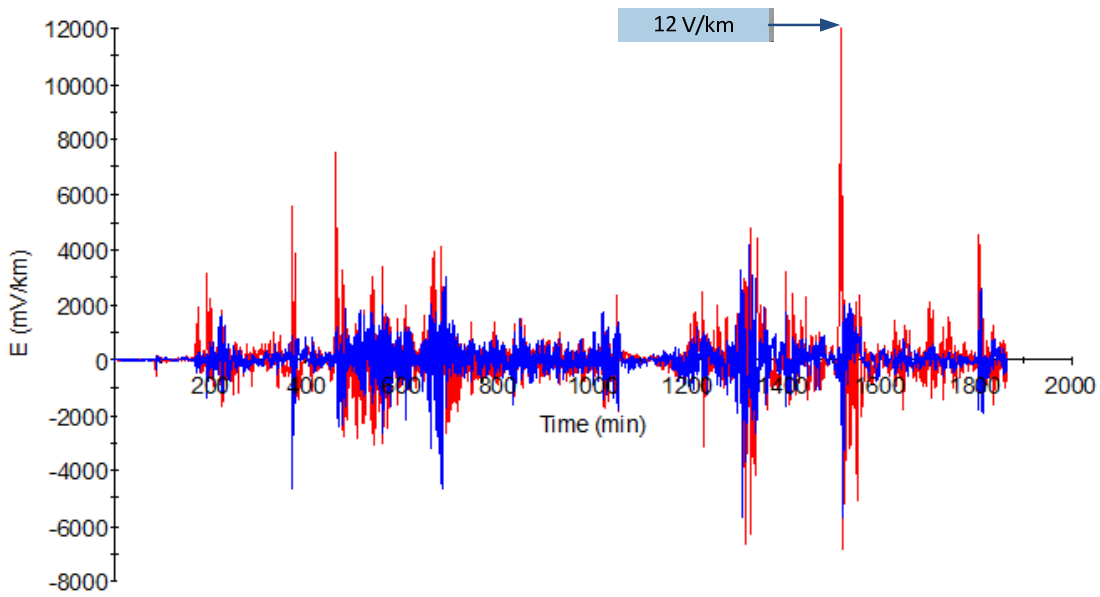


Figure 7: Supplemental Geoelectric Field Waveform
Blue E_N (Northward), Red E_E (Eastward)

Attachment 1-CAN

Attachment 1-CAN provides an alternative that any 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] 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).

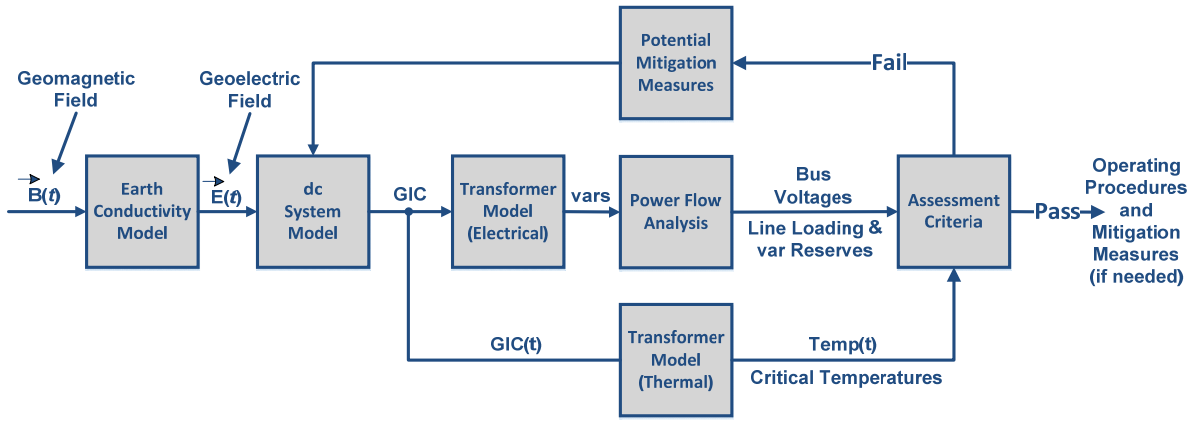
For the benchmark GMD Vulnerability Assessment(s), an entity shall consider the large-scale spatial structure of the GMD event. For the supplemental GMD Vulnerability Assessment(s), an

[1] The “earth transfer function” is the relationship between the electric fields and magnetic field variations at the surface of the earth.

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: *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

[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.
[13] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf.

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 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.

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[14] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.

[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.

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 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

[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.
[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.

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 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

[22] http://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-007-1_Transformer_Thermal_Impact_Assessment_White_Paper.pdf.
[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.

studies may provide more useful information for validation and situational awareness purposes. Conversely, data from GIC monitors that are located in the vicinity of transportation systems using direct current (e.g., subways or light rail) may be unreliable.

- **Monitor specifications.** Capabilities of Hall effect transducers, existing and planned, should be considered in the operating process. When planning new GIC monitor installations, consider monitor data range (e.g., -500 A through + 500 A) and ambient temperature ratings consistent with temperatures in the region in which the monitor will be installed.

- **Sampling Interval.** An entity's operating process may be constrained by capabilities of existing GIC monitors. However, when possible specify data sampling during periods of interest at a rate of 10 seconds or faster.

- **Collection Periods.** The process should specify when the entity expects GIC data to be collected. For example, collection could be required during periods where the Kp index is above a threshold, or when GIC values are above a threshold. Determining when to discontinue collecting GIC data should also be specified to maintain consistency in data collection.

- **Data format.** Specify time and value formats. For example, Greenwich Mean Time (GMT) (MM/DD/YYYY HH:MM:SS) and GIC Value (Ampere). Positive (+) and negative (-) signs indicate direction of GIC flow. Positive reference is flow from ground into transformer neutral. Time fields should indicate the sampled time rather than system or SCADA time if supported by the GIC monitor system.

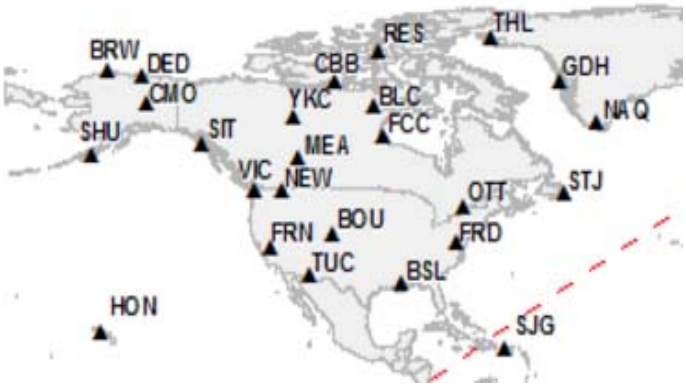
- **Data retention.** The entity's process should specify data retention periods, for example 1 year. Data retention periods should be adequately long to support availability for the entity's model validation process and external reporting requirements, if any.

- **Additional information.** The entity's process should specify collection of other information necessary for making the data useful, for example monitor location and type of neutral connection (e.g., three-phase or single-phase).

Requirement R12

Magnetometers measure changes in the earth's magnetic field. Entities should obtain data from the nearest accessible magnetometer. Sources of magnetometer data include:

- Observatories such as those operated by U.S. Geological Survey and Natural Resources Canada, see figure below for locations:[26]



- Research institutions and academic universities;
- Entities with installed magnetometers.

Entities that choose to install magnetometers should consider equipment specifications and data format protocols contained in the latest version of the *INTERMAGNET Technical Reference Manual*, Version 4.6, 2012.[27]

[26] http://www.intermagnet.org/index-eng.php.
[27] http://www.intermagnet.org/publications/intermag_4-6.pdf.

Rationale

During development of TPL-007-1, text boxes were embedded within the standard to explain the rationale for various parts of the standard. The text from the rationale text boxes was moved to this section upon approval of TPL-007-1 by the NERC Board of Trustees. In developing TPL-007-2, the SDT has made changes to the sections below only when necessary for clarity. Changes are marked with brackets [ ].

Rationale for Applicability:

Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these transformers are not included in the applicability for this standard.

Terminal voltage describes line-to-line voltage.

Rationale for R1:

In some areas, planning entities may determine that the most effective approach to conduct a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

Rationale for R2:

A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model is provided in the *Application Guide Computing Geomagnetically-Induced Current in the Bulk-Power System*,[28] December 2013, developed by the NERC GMD Task Force.

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformer(s) due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include, for example, recalling or postponing maintenance outages.

The Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1, which is proposed for revision in the NERC filing dated August 29, 2014 (Docket No. RM12-1-000). NERC guidelines require consistency among Reliability Standards.

[28] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf.

Rationale for R3:

Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1. Steady state voltage limits are an example of System steady state performance criteria.

Rationale for R4:

The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The *Geomagnetic Disturbance Planning Guide*,[29] December 2013 developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. The provision of information in Requirement R4, Part 4.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R5:

This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment.

GIC(t) provided in Part 5.2 can alternatively be used to convert the steady state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the *Transformer Thermal Impact Assessment White Paper*,[30] October 2017.

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

[29] http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf.
[30] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1.

The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R6:

The transformer thermal impact screening criterion has been revised from 15 A per phase to 75 A per phase [for the benchmark GMD event]. Only those transformers that experience an effective GIC value of 75 A per phase or greater require evaluation in Requirement R6. The justification is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*,[31] October 2017.

The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment White Paper*,[32] October 2017.

Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

The provision of information in Requirement R6, Part 6.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R7:

The proposed requirement addresses directives in Order No. 830 for establishing Corrective Action Plan (CAP) deadlines associated with GMD Vulnerability Assessments. In Order No. 830, FERC directed revisions to TPL-007 such that CAPs are developed within one year from the completion of GMD Vulnerability Assessments (P 101). Furthermore, FERC directed establishment of implementation deadlines after the completion of the CAP as follows (P 102):

- Two years for non-hardware mitigation; and
- Four years for hardware mitigation.

The objective of Part 7.4 is to provide awareness to potentially impacted entities when implementation of planned mitigation is not achievable within the deadlines established in Part

[31] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.
[32] http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

7.3. Examples of situations beyond the control of the responsible entity (see Section 7.4) 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.

Rationale for Table 3:

Table 3 has been revised to use the same ground model designation, FL1, as is being used by USGS. The calculated scaling factor for FL1 is 0.74. [The scaling factor associated with the benchmark GMD event for the Florida earth model (FL1) has been updated to 0.76 in TPL-007-2 based on the earth model published on the USGS public website.]

Rationale for R8 – R10:

The proposed requirements address directives in Order No. 830 for revising the benchmark GMD event used in GMD Vulnerability Assessments (P 44, P 47-49). The requirements add a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for localized peak geoelectric fields.

Rationale for R11 – R12:

The proposed requirements address directives in Order No. 830 for requiring responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness (P 88; P. 90-92). GMD measurement data refers to GIC monitor data and geomagnetic field data in Requirements R11 and R12, respectively. See the Guidelines and Technical Basis section of this standard for technical information.

The objective of Requirement R11 is for entities to obtain GIC data for the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model to inform GMD Vulnerability Assessments. Technical considerations for GIC monitoring are contained in Chapter 9 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System* (NERC 2012 GMD Report). GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the transformer and measure dc current flowing through the neutral.

The objective of Requirement R12 is for entities to obtain geomagnetic field data for the Planning Coordinator's planning area to inform GMD Vulnerability Assessments. Magnetometers provide geomagnetic field data by measuring changes in the earth's magnetic field. Sources of geomagnetic field data include:

- Observatories such as those operated by U.S. Geological Survey, Natural Resources Canada, research organizations, or university research facilities;
- Installed magnetometers; 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.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2018-01 Canadian-Specific Revisions to TPL-007-2

Applicable Standard(s)

- TPL-007-3- Transmission System Planned Performance for Geomagnetic Disturbance Events

Requested Retirement(s)

- TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events
- TPL-007-2 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Standard(s)

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

In January 2018, NERC submitted for regulatory approval Reliability Standard TPL-007-2. This standard was developed in response to certain directives of the United States Federal Energy Regulatory Commission (FERC) from Order No. 830 (September 22, 2016), approving Reliability Standard TPL-007-1 and its associated five-year Implementation Plan and directing certain modifications.

In May 2018, a Standard Authorization Request was submitted identifying a need for a Canadian-specific Variance to the TPL-007-2 standard. Specifically, the Standard Authorization Request sought to provide an option for Canadian Registered Entities to define alternative Benchmark GMD Events and/or Supplemental GMD Events specific to their unique topology.

Reliability Standard TPL-007-3 adds a Variance for Canadian entities. The Canadian Variance replaces, in its entirety, Requirement R7, Part 7.3 of the continent-wide standard for Canadian entities and adds an alternate methodology for GMD Vulnerability Assessments, as described in Attachment 1-CAN. None of the continent-wide Requirements have been changed.

Effective Date and Phased-In Compliance Dates

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 a proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date 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-007-3

United States

The standard shall become effective on the later of: (1) the effective date of Reliability Standard TPL-007-2; or (2) the first day of the first calendar quarter after the date TPL-007-3 is adopted by the NERC Board of Trustees.

This implementation plan incorporates by reference the phased-in compliance dates of the TPL-007-2 implementation plan (see Attachment 1).

All Other Jurisdictions

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 three (3) 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 three (3) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

This implementation plan incorporates by reference the phased-in compliance dates of the TPL-007-2 implementation plan (see Attachment 1), except that the phased-in compliance dates described therein shall be based on the effective date of TPL-007-3.

Attachment 1-
TPL-007-2 Implementation Plan

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Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation
Reliability Standard TPL-007-2

Applicable Standard

- TPL-007-2 - Transmission System Planned Performance for Geomagnetic Disturbance Events

Requested Retirement

- TPL-007-1 - 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 September 22, 2016, the Federal Energy Regulatory Commission (FERC) issued Order No. 830 approving Reliability Standard TPL-007-1 and its associated five-year Implementation Plan. In the Order, FERC also directed NERC to develop certain modifications to the standard. FERC established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which is May 2018.

General Considerations

This Implementation Plan is intended to integrate the new requirements in TPL-007-2 with the GMD Vulnerability Assessment process that is being implemented through approved TPL-007-1. At the time of the May 2018 filing deadline, many requirements in approved standard TPL-007-1 that lead

to completion of the geomagnetic disturbance (GMD) Vulnerability Assessment will be in effect. Furthermore, many entities may be taking steps to complete studies or assessments that are required by future enforceable requirements in TPL-007-1. The Implementation Plan phases in the requirements in TPL-007-2 based on the effective date of TPL-007-2, as follows:

- **Effective Date before January 1, 2021**. Implementation timeline supports applicable entities completing new requirements for supplemental GMD Vulnerability Assessments concurrently with requirements for the benchmark GMD Vulnerability Assessment (concurrent effective dates).

- **Effective Date on or after January 1, 2021**. Implementation timeline supports applicable entities completing the benchmark GMD Vulnerability Assessments before new requirements for supplemental GMD Vulnerability Assessments become effective.

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.

Standard TPL-007-2

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 three (3) 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 three (3) 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

If TPL-007-2 becomes effective before January 1, 2021

Implementation timeline supports applicable entities completing new requirements for supplemental GMD Vulnerability Assessments concurrently with requirements for the benchmark GMD Vulnerability Assessment (concurrent effective dates).

Compliance Date for TPL-007-2 Requirements R1 and R2

Entities shall be required to comply with Requirements R1 and R2 upon the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R5
Entities shall not be required to comply with Requirements R5 until six (6) months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R9
Entities shall not be required to comply with Requirement R9 until six (6) months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R11 and R12
Entities shall not be required to comply with Requirements R11 and R12 until 24 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R6 and R10
Entities shall not be required to comply with Requirements R6 and R10 until 30 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R3, R4, and R8
Entities shall not be required to comply with Requirements R3, R4, and R8 until 42 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R7
Entities shall not be required to comply with Requirement R7 until 54 months after the effective date of Reliability Standard TPL-007-2.

If TPL-007-2 becomes effective on or after January 1, 2021

Implementation timeline supports applicable entities completing the benchmark GMD Vulnerability Assessments before new requirements for supplemental GMD Vulnerability Assessments become effective.

Compliance Date for TPL-007-2 Requirements R1, R2, R5, and R6
Entities shall be required to comply with Requirements R1, R2, R5, and R6 upon the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R3 and R4
Entities shall not be required to comply with Requirements R3 and R4 until 12 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R7, R11, and R12
Entities shall not be required to comply with Requirements R7, R11, and R12 until 24 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R9
Entities shall not be required to comply with Requirement R9 until 36 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R10
Entities shall not be required to comply with Requirement R10 until 60 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R8
Entities shall not be required to comply with Requirement R8 until 72 months after the effective date of Reliability Standard TPL-007-2.

Retirement Date

Standard TPL-007-1
Reliability Standard TPL-007-1 shall be retired immediately prior to the effective date of TPL-007-2 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.

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Violation Risk Factor and Violation Severity Level Justifications

TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events

The Project 2018-01 Standard Drafting Team reviewed the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in Reliability Standard TPL-007-2 (Transmission System Planned Performance for Geomagnetic Disturbance Events) and determined that no modifications to the VRFs and VSLs are necessary for the proposed TPL-007-3 (Canadian Variance). Since the VRFs and VSLs do not require modifications, the applicable justifications for those VRFs and VSLs will also remain the same as applied to the proposed TPL-007-2 (Canadian Variance).

- TPL-007-2 VRF and VSL Justifications

Standard Development Timeline

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

Description of Current Draft

This is the ~~first~~ second draft of proposed standard for formal 15~~20~~-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	August 9, 2018
SAR posted for comment	August 10 – September 10, 2018
20-day formal comment period with ballot	October 2018

Anticipated Actions	Date
~~20-day formal comment period with ballot~~	~~October 2018~~
15-day formal comment period with additional ballot	November 2018
5-day final ballot	January 2019
Board adoption	February 2019

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.

Proposed Modified Terms:

Cyber Security Incident:

A malicious act or suspicious event that:

- Compromises, or was an attempt to compromise the, (1) Electronic Security Perimeter, ~~or~~ (2) Physical Security Perimeter ~~or~~, (3) Electronic Access Control or ~~f~~ Monitoring Systems for High or Medium Impact BES Cyber Systems; ~~,~~ or ~~;~~
- Disrupts, or was an attempt to disrupt, the operation of a BES Cyber S~~s~~ystem.

Reportable Cyber Security Incident:

A Cyber Security Incident that has compromised or disrupted:

- A BES Cyber System that performs o~~O~~ne or more reliability tasks of a functional entity; ~~or~~
- Electronic Security Perimeter(s); or
- Electronic Access Control or Monitoring Systems. ~~(EACMS) that provide any of the following functions: (1) authentication; (2) monitoring and logging; (3) access control; (4) Interactive Remote Access; or (5) alerting.~~

~~**Proposed New Term:**~~

~~Reportable Attempted Cyber Security Incident:~~

~~A Cyber Security Incident that was an attempt to compromise or disrupt:~~

- ~~One or more reliability tasks of a functional entity; or~~
- ~~Electronic Security Perimeter; or~~
- ~~Electronic Access Control or Monitoring System (EACMS) that provide any of the following functions: (1) authentication; (2) monitoring and logging; (3) access control; (4) Interactive Remote Access; or (5) alerting~~

A. Introduction

1. Title: Cyber Security — Incident Reporting and Response Planning

2. Number: CIP-008-6

3. Purpose: To mitigate the risk to the reliable operation of the BES as the result of a Cyber Security Incident by specifying incident response requirements.

4. Applicability:

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

4.1.1 Balancing Authority

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

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

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

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

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

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

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

4.1.3 Generator Operator

4.1.4 Generator Owner

4.1.5 Reliability Coordinator

4.1.6 Transmission Operator

4.1.7 Transmission Owner

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

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

4.2.1.1 Each UFLS or UVLS System that:

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

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

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

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

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

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-008-6:

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

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

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

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

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

5. Effective Dates:

See Implementation Plan for CIP-008-6.

6. Background:

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

Most requirements open with, "*Each Responsible Entity shall implement one or more documented [processes, plan, etc] 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 must address the applicable requirements in the table.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it~~-~~ 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 particular subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

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

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

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

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

"Applicable Systems" Columns in Tables:

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

- **High Impact BES Cyber Systems –** Applies to BES Cyber Systems categorized as high impact according to the CIP-002 identification and categorization processes.
- **Medium Impact BES Cyber Systems –** Applies to BES Cyber Systems categorized as medium impact according to the CIP-002 identification and categorization processes.

B. Requirements and Measures

R1. Each Responsible Entity shall document one or more Cyber Security Incident response plan(s) that collectively include each of the applicable requirement parts in *CIP-008-6 Table R1 – Cyber Security Incident Response Plan Specifications*. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning].*

M1. Evidence must include each of the documented plan(s) that collectively include each of the applicable requirement parts in *CIP-008-6 Table R1 – Cyber Security Incident Response Plan Specifications*.

CIP-008-6 Table R1 – Cyber Security Incident Response Plan Specifications			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.1	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	One or more processes to identify, classify, and respond to Cyber Security Incidents.	An example of evidence may include, but is not limited to, dated documentation of Cyber Security Incident response plan(s) that include the process to identify, classify, and respond to Cyber Security Incidents.

CIP-008-6 Table R1 – Cyber Security Incident Response Plan Specifications			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.2	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	One or more processes to: 1.2.1 Establish criteria to evaluate and define attempts to compromise; 1.2.2 D~~d~~etermine if an identified Cyber Security Incident is: • A~~ a~~ Reportable Cyber Security Incident or • Only an attempt to compromise one or more systems identified in the "Applicable Systems" column for this Part; ~~a Reportable Attempted Cyber Security Incident and requires notification per Requirement R4~~and ~~1.2.1~~1.2.3 Provide notification per Requirement R4.	Examples of evidence may include, but are not limited to, dated documentation of Cyber Security Incident response plan(s) that provide guidance or thresholds for determining which Cyber Security Incidents are also Reportable Cyber Security Incidents or a Cyber Security Incident that ~~involves~~is determined to be only an attempt to compromise a system identified in the "Applicable Systems" column including~~s~~ justification for attempt determination criteria ~~Reportable Attempted Cyber Security Incidents~~ and documented processes for notification.

CIP-008-6 Table R1 – Cyber Security Incident Response Plan Specifications			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.3	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	The roles and responsibilities of Cyber Security Incident response groups or individuals.	An example of evidence may include, but is not limited to, dated Cyber Security Incident response process(es) or procedure(s) that define roles and responsibilities (e.g., monitoring, reporting, initiating, documenting, etc.) of Cyber Security Incident response groups or individuals.
1.4	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	Incident handling procedures for Cyber Security Incidents.	An example of evidence may include, but is not limited to, dated Cyber Security Incident response process(es) or procedure(s) that address incident handling (e.g., containment, eradication, recovery/incident resolution).

R2. Each Responsible Entity shall implement each of its documented Cyber Security Incident response plans to collectively include each of the applicable requirement parts in *CIP-008-6 Table R2 – Cyber Security Incident Response Plan Implementation and Testing. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning and Real-Time Operations].*

M2. Evidence must include, but is not limited to, documentation that collectively demonstrates implementation of each of the applicable requirement parts in *CIP-008-6 Table R2 – Cyber Security Incident Response Plan Implementation and Testing*.

CIP-008-6 Table R2 – Cyber Security Incident Response Plan Implementation and Testing			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	Test each Cyber Security Incident response plan~~(s)~~ at least once every 15 calendar months: • By responding to an actual Reportable Cyber Security Incident; • With a paper drill or tabletop exercise of a Reportable Cyber Security Incident; or • With an operational exercise of a Reportable Cyber Security Incident.	Examples of evidence may include, but are not limited to, dated evidence of a lessons-learned report that includes a summary of the test or a compilation of notes, logs, and communication resulting from the test. Types of exercises may include discussion or operations based exercises.
2.2	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	Use the Cyber Security Incident response plan(s) under Requirement R1 when responding to a Reportable Cyber Security Incident, ~~Reportable Attempted~~ Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part, or performing an exercise of a Reportable Cyber Security Incident. Document deviations from the plan(s) taken during the response to the incident or exercise.	Examples of evidence may include, but are not limited to, incident reports, logs, and notes that were kept during the incident response process, and follow-up documentation that describes deviations taken from the plan during the incident response or exercise.

CIP-008-6 Table R2 – Cyber Security Incident Response Plan Implementation and Testing			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.3	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	Retain records related to Reportable Cyber Security Incidents and ~~Reportable Attempted~~ Cyber Security Incidents that attempted to compromise a system identified in the "Applicable Systems" column for this Part.	An example of evidence may include, but is not limited to, dated documentation, such as security logs, police reports, emails, response forms or checklists, forensic analysis results, restoration records, and post-incident review notes related to Reportable Cyber Security Incidents and ~~Reportable Attempted~~ Cyber Security Incident~~s~~ that ~~involves~~ is determined to be only an attempt to compromise a system identified in the "Applicable Systems" column.

R3. Each Responsible Entity shall maintain each of its Cyber Security Incident response plans according to each of the applicable requirement parts in *CIP-008-6 Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication*. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment].*

M3. Evidence must include, but is not limited to, documentation that collectively demonstrates maintenance of each Cyber Security Incident response plan according to the applicable requirement parts in *CIP-008-6 Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication*.

CIP-008-6 Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.1	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	No later than 90 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident response: 3.1.1. Document any lessons learned or document the absence of any lessons learned; 3.1.2. Update the Cyber Security Incident response plan based on any documented lessons learned associated with the plan; and 3.1.3. Notify each person or group with a defined role in the Cyber Security Incident response plan of the updates to the Cyber Security Incident response plan based on any documented lessons learned.	An example of evidence may include, but is not limited to, all of the following: 1. Dated documentation of post incident(s) review meeting notes or follow-up report showing lessons learned associated with the Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident response or dated documentation stating there were no lessons learned; 2. Dated and revised Cyber Security Incident response plan showing any changes based on the lessons learned; and 3. Evidence of plan update distribution including, but not limited to: • Emails; • USPS or other mail service; • Electronic distribution system; or • Training sign-in sheets.

CIP-008-6 Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.2	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	No later than 60 calendar days after a change to the roles or responsibilities, Cyber Security Incident response groups or individuals, or technology that the Responsible Entity determines would impact the ability to execute the plan: 3.2.1. Update the Cyber Security Incident response plan(s); and 3.2.2. Notify each person or group with a defined role in the Cyber Security Incident response plan of the updates.	An example of evidence may include, but is not limited to: 1. Dated and revised Cyber Security Incident response plan with changes to the roles or responsibilities, responders or technology; and 2. Evidence of plan update distribution including, but not limited to: • Emails; • USPS or other mail service; • Electronic distribution system; or • Training sign-in sheets.

R4. Each Responsible Entity shall notify the Electricity Information Sharing and Analysis Center (E-ISAC) and, if subject to the jurisdiction of the United States, the United States National Cybersecurity and Communications Integration Center (NCCIC)[1], or their successors, ~~Each Responsible Entity shall notify the Electricity Information Sharing and Analysis Center (E-ISAC) and each United States Responsible Entity also shall notify the Industrial Control Systems Cyber Emergency Response Team (ICS-CERT), or their successors,~~ of a Reportable Cyber Security Incident~~s~~ and a Cyber Security Incident that was only an attempt to compromise a system identified in the "Applicable Systems" column~~Reportable Attempted Cyber Security Incidents~~, unless prohibited by law, in accordance with~~ing to~~ each of the applicable requirement parts in *CIP-008-6 Table R4 – Notifications and Reporting for Cyber Security Incidents*. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment].*

M4. Evidence must include, but is not limited to, documentation that collectively demonstrates notification of each determined Reportable Cyber Security Incident and a Cyber Security Incident that was an attempt to compromise a system identified in the "Applicable Systems" column -according to the applicable requirement parts in *CIP-008-6 Table R4 – Notifications and Reporting for Cyber Security Incidents.*

[1] The National Cybersecurity and Communications Integration Center (NCCIC) is the successor organization of the Industrial Control Systems Cyber Emergency Response Team (ICS-CERT). In 2017, NCCIC realigned its organizational structure and integrated like functions previously performed independently by the ICS-CERT and the United States Computer Emergency Readiness Team (US-CERT).

CIP-008-6 Table R4 – Notifications and Reporting for Cyber Security Incidents			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.1	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	~~Except for Reportable Cyber Security Incidents compromising or disrupting a Physical Security Perimeter, I~~initial notifications and updates shall include the following attributes, at a minimum, to the extent known: 4.1.1 The functional impact; 4.1.2 The attack vector used; and 4.1.3 The level of intrusion that was achieved or attempted.	Examples of evidence may include, but are not limited to, dated documentation of initial notifications and updates to the E-ISAC and ~~ICS-CERT~~NCCIC. ~~in the form of Attachment 1 submissions.~~
~~4.2~~	~~High Impact BES Cyber Systems and their associated:~~ ~~• EACMS~~ ~~Medium Impact BES Cyber Systems and their associated:~~ ~~• EACMS~~	~~Responsible Entities shall use one of the following methods for initial notification:~~ ~~• Electronic submission of Attachment 1;~~ ~~• Phone; or~~ ~~• Email.~~ ~~If Attachment 1 was not submitted for initial notification, it must be submitted within 5 calendar days of initial notification, without attribute information if undetermined at the time of submittal.~~	~~Examples of evidence may include, but are not limited to, dated documentation of notices to the E-ISAC and ICS-CERT in the form of electronic submissions of Attachment 1, phone records or email.~~

CIP-008-6 Table R4 – Notifications and Reporting for Cyber Security Incidents			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.2~~3~~	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	After the Responsible Entity's determination made pursuant to documented process(es) in Requirement R1, Part 1.2, provide initial notification within the following timelines~~Timeline for initial notification~~: • One hour ~~from~~ after the determination of a Reportable Cyber Security Incident. • By the end of the next calendar day after ~~a~~ determination that a ~~of a Reportable Attempted~~ Cyber Security Incident was only an attempt to compromise a system identified in the "Applicable Systems" column for this Part.	Examples of evidence may include, but are not limited to, dated documentation of notices to the E-ISAC and ~~ICS-CERT~~NCCIC. ~~in the form of phone records for preliminary notice or submissions through the E-ISAC and ICS-CERT approved methods, or Attachment 1 submissions.~~
4.3~~4~~	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	~~Responsible Entities shall submit~~ Provide ~~Attachment 1~~ updates ~~for the attributes required in Part 4.1~~ within 7~~5~~ calendar days of determination of new or changed attribute information required in Part 4.1~~. Submissions must occur each time new attribute information is available until all attributes have been reported.~~	Examples of evidence may include, but are not limited to, dated documentation of ~~Attachment 1~~ submissions to the E-ISAC and ~~ICS-CERT~~NCCIC.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long Term Planning**	**Lower**	N/A	N/A	The Responsible Entity has developed the Cyber Security Incident response plan(s), but the plan does not include the roles and responsibilities of Cyber Security Incident response groups or individuals. (1.3) OR The Responsible Entity has developed the Cyber Security Incident response plan(s), but the plan does not include incident handling procedures for Cyber Security Incidents. (1.4) OR	The Responsible Entity has not developed a Cyber Security Incident response plan with one or more processes to identify, classify, and respond to Cyber Security Incidents. (1.1) OR The Responsible Entity has developed a Cyber Security Incident response plan, but the plan does not include one or more processes to identify Reportable Cyber Security Incidents or ~~Reportable Attempted~~ a Cyber Security Incident~~s~~ that was only an attempt to compromise a system identified in the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					The Responsible Entity has developed a Cyber Security Incident response plan, but the plan does not include one or more processes to provide notification per Requirement R4. (1.2) OR The Responsible Entity has developed a Cyber Security Incident response plan, but the plan does not include one or more processes to establish criteria to evaluate and define attempts to compromise. (1.2)	"Applicable Systems" column for Part 1.2. (1.2)
R2	**Operations Planning** **Real-time Operations**	**Lower**	The Responsible Entity has not tested the Cyber Securit y Incident response plan(s) within 15 calendar months, not	The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 16 calendar months, not	The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 17 calendar months, not	The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 18 calendar months

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			exceeding 16 calendar months between tests of the plan. (2.1)	exceeding 17 calendar months between tests of the plan. (2.1)	exceeding 18 calendar months between tests of the plan. (2.1) OR The Responsible Entity did not document deviations, if any, from the plan during a test or when a Reportable Cyber Security Incident or ~~Reportable Attempted~~ a Cyber Security Incident that was only an attempt to compromise a system identified in the "Applicable Systems" column for Part 2.2 occurs. (2.2)	between tests of the plan. (2.1) OR The Responsible Entity did not retain relevant records related to Reportable Cyber Security Incidents or ~~Reportable Attempted~~ Cyber Security Incidents that were only an attempt to compromise a system identified in the "Applicable Systems" column for 2.3. (2.3)
R3	**Operations Assessment**	**Lower**	The Responsible Entity has not notified each person or group with a defined role in the Cyber Security Incident response plan of updates to the Cyber Security	The Responsible Entity has not updated the Cyber Security Incident response plan based on any documented lessons learned within 90 and	The Responsible Entity has neither documented lessons learned nor documented the absence of any lessons learned within 90 and	The Responsible Entity has neither documented lessons learned nor documented the absence of any lessons learned within

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Incident response plan within greater than 90 but less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.3)	less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.2) OR The Responsible Entity has not notified each person or group with a defined role in the Cyber Security Incident response plan of updates to the Cyber Security Incident response plan within 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.3) OR The Responsible Entity has not updated the Cyber Security Incident response plan(s) or notified	less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.1) OR The Responsible Entity has not updated the Cyber Security Incident response plan based on any documented lessons learned within 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.2) OR The Responsible Entity has not updated the Cyber Security Incident response plan(s) or notified each person or group with a defined role	120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.1)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				each person or group with a defined role within 60 and less than 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2) • Roles or responsibilities, or • Cyber Security Incident response groups or individuals, or • Technology changes.	within 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2) • Roles or responsibilities, or • Cyber Security Incident response groups or individuals, or • Technology changes.	
R4	**Operations Assessment**	**Lower**	The Responsible Entity notified E-ISAC and NCCIC, or their successors, of a Cyber Security Incident that was only an attempt to compromise a system identified in the "Applicable Systems" column for	The Responsible Entity failed to notify E-ISAC or NCCIC, or their successors, of a Cyber Security Incident that was only an attempt to compromise a system identified in	The Responsible Entity notified E-ISAC and ~~ICS-CERT~~NCCIC, or their successors, of a Reportable Cyber Security Incident but failed to notify or update E-ISAC or ~~ICS-CERT~~NCCIC, or their successors, within the	The Responsible Entity failed to notify E-ISAC ~~or~~ and ~~ICS-CERT~~NCCIC, or their successors, of a Reportable Cyber Security Incident ~~or Reportable Attempted Cyber Security Incident~~. (R4)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Part 4.2 but failed to notify or update E-ISAC or NCCIC, or their successors, within the timelines pursuant to Requirement R4, Part 4.2. (4.2) OR The Responsible Entity notified E-ISAC and NCCIC, or their successors, of a Reportable Cyber Security Incident or a Cyber Security Incident that was only an attempt to compromise a system identified in the "Applicable Systems" column for Part 4.3 but failed to report on one or more of the attributes within 7 days after determination of the attribute(s) not reported pursuant to	the "Applicable Systems" column. (R4) ~~The Responsible Entity notified E-ISAC and ICS-CERT, or their successors, of a Reportable Cyber Security Incident or Reportable Attempted Cyber Security Incident but failed to report on one or more of the attributes within the timeframes pursuant to Requirement R4, Part 4.4 after determination of the attribute(s) not reported pursuant to Requirement R4, Part 4.1. (4.4)~~ ~~OR~~ ~~The Responsible Entity notified E-ISAC and ICS-CERT, or their successors, of a Reportable Cyber~~	~~timeframes~~ timelines pursuant to Requirement R4, Part 4.2~~3~~. (4.2) OR The Responsible Entity failed to notify E-ISAC or NCCIC, or their successors, of a Reportable Cyber Security Incident. (R4)	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Requirement R4, Part 4.1. (4.3) OR The Responsible Entity notified E-ISAC and NCCIC, or their successors, of a Reportable Cyber Security Incident or a Cyber Security Incident that was only an attempt to compromise a system identified in the "Applicable Systems" column for Part 4.1 but failed to report on one or more of the attributes after determination pursuant to Requirement R4, Part 4.1. (4.1) ~~The Responsible Entity notified E-ISAC and ICS-CERT, or their successors, of a Reportable Cyber~~	~~Security Incident or Reportable Attempted Cyber Security Incident but failed to report on one or more of the attributes after determination of the attribute pursuant to Requirement R4, Part 4.1.~~		

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~Security Incident or Reportable Attempted Cyber Security Incident and the attributes within the timeframes pursuant to Requirement R4, Parts 4.1 and 4.3 but failed to submit the form in Attachment 1. (4.4)~~ ~~OR~~ ~~The Responsible Entity notified E-ISAC and ICS-CERT, or their successors, of a Reportable Cyber Security Incident or Reportable Attempted Cyber Security Incident and the attributes within the timeframes pursuant to Requirement R4, Parts 4.1 and 4.3 but failed to use one of the methods for initial notification pursuant~~			

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~to Requirement R4, Part 4.2.~~			

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

~~Guidelines and Technical Basis~~

~~*Note: The Guidelines and Technical Basis section has not been revised as part of Project 2018-02. A separate technical rationale document has been created to cover Project 2018-02 revisions. Future edits to this section will be conducted through the Technical Rationale for Reliability Standards Project and the Standards Drafting Process.*~~

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

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

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

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

~~Requirement R1:~~

~~The following guidelines are available to assist in addressing the required components of a Cyber Security Incident response plan:~~

- ~~Department of Homeland Security, Control Systems Security Program, *Developing an Industrial Control Systems Cyber Security Incident Response Capability*, 2009, online at http://www.us-cert.gov/control_systems/practices/documents/final-RP_ics_cybersecurity_incident_response_100609.pdf~~
- ~~National Institute of Standards and Technology, *Computer Security Incident Handling Guide*, Special Publication 800-61 revision 1, March 2008, online at http://csrc.nist.gov/publications/nistpubs/800-61-rev1/SP800-61rev1.pdf~~

~~For Part 1.2, a Reportable Cyber Security Incident is a Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity. It is helpful to distinguish Reportable Cyber Security Incidents as one resulting in a necessary response action. A response action can fall into one of two categories: Necessary or elective. The distinguishing~~

~~characteristic is whether or not action was taken in response to an event. Precautionary measures that are not in response to any persistent damage or effects may be designated as elective. All other response actions to avoid any persistent damage or adverse effects, which include the activation of redundant systems, should be designated as necessary.~~

~~The reporting obligations for Reportable Cyber Security Incidents require at least a preliminary notice to the ES-ISAC within one hour after determining that a Cyber Security Incident is reportable (not within one hour of the Cyber Security Incident, an important distinction). This addition is in response to the directive addressing this issue in FERC Order No. 706, paragraphs 673 and 676, to report within one hour (at least preliminarily). This standard does not require a complete report within an hour of determining that a Cyber Security Incident is reportable, but at least preliminary notice, which may be a phone call, an email, or sending a Web-based notice. The standard does not require a specific timeframe for completing the full report.~~

~~Requirement R2:~~

~~Requirement R2 ensures entities periodically test the Cyber Security Incident response plan. This includes the requirement in Part 2.2 to ensure the plan is actually used when testing. The testing requirements are specifically for *Reportable Cyber Security Incidents*.~~

~~Entities may use an actual response to a *Reportable Cyber Security Incident* as a substitute for exercising the plan annually. Otherwise, entities must exercise the plan with a paper drill, tabletop exercise, or full operational exercise. For more specific types of exercises, refer to the FEMA Homeland Security Exercise and Evaluation Program (HSEEP). It lists the following four types of discussion-based exercises: seminar, workshop, tabletop, and games. In particular, it defines that, "A tabletop exercise involves key personnel discussing simulated scenarios in an informal setting. Table top exercises (TTX) can be used to assess plans, policies, and procedures."~~

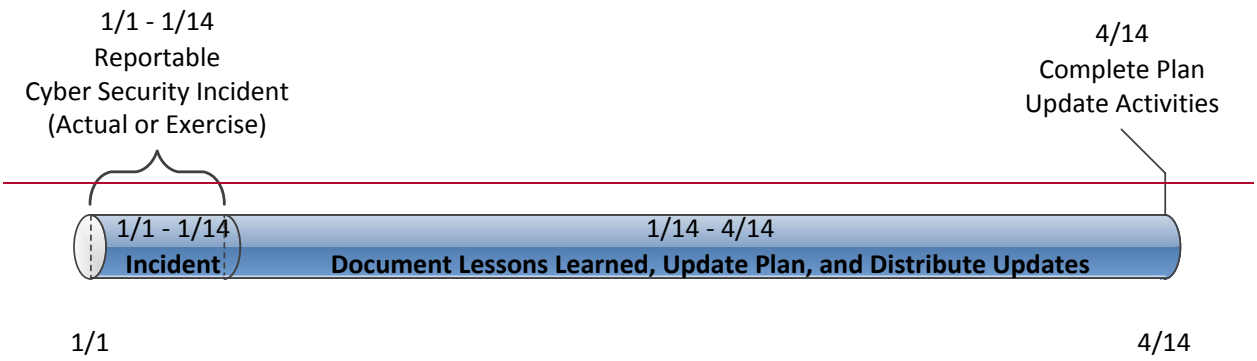
~~The HSEEP lists the following three types of operations-based exercises: Drill, functional exercise, and full-scale exercise. It defines that, "[A] full-scale exercise is a multi-agency, multi-jurisdictional, multi-discipline exercise involving functional (e.g., joint field office, Emergency operation centers, etc.) and 'boots on the ground' response (e.g., firefighters decontaminating mock victims)."~~

~~In addition to the requirements to implement the response plan, Part 2.3 specifies entities must retain relevant records for *Reportable Cyber Security Incidents*. There are several examples of specific types of evidence listed in the measure. Entities should refer to their handling procedures to determine the types of evidence to retain and how to transport and store the evidence. For further information in retaining incident records, refer to the NIST Guide to Integrating Forensic Techniques into Incident Response (SP800-86). The NIST guideline includes a section (Section 3.1.2) on acquiring data when performing forensics.~~

~~Requirement R3:~~

~~This requirement ensures entities maintain Cyber Security Incident response plans. There are two requirement parts that trigger plan updates: (1) lessons learned from Part 3.1 and (2) organizational or technology changes from Part 3.2.~~

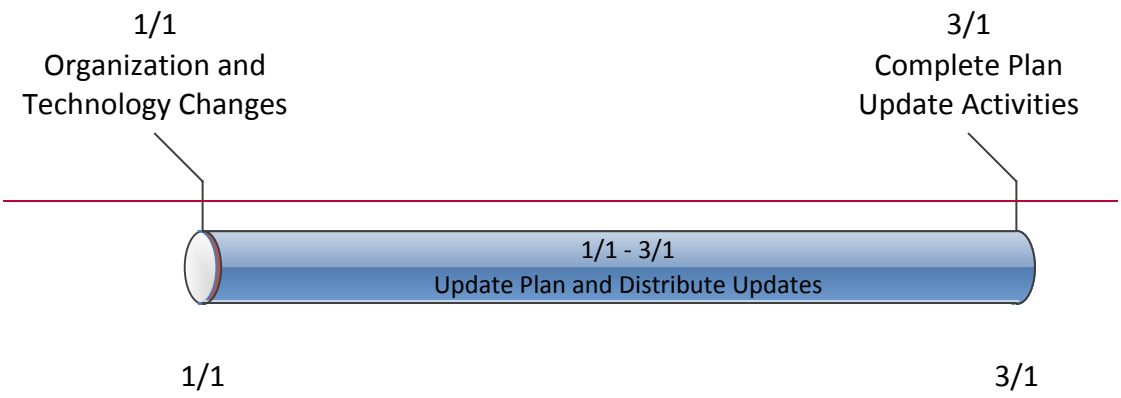
~~The documentation of lessons learned from Part 3.1 is associated with each Reportable Cyber Security Incident and involves the activities as illustrated in Figure 1, below. The deadline to document lessons learned starts after the completion of the incident in recognition that complex incidents on complex systems can take a few days or weeks to complete response activities. The process of conducting lessons learned can involve the response team discussing the incident to determine gaps or areas of improvement within the plan. Any documented deviations from the plan from Part 2.2 can serve as input to the lessons learned. It is possible to have a *Reportable Cyber Security Incident* without any documented lessons learned. In such cases, the entity must retain documentation of the absence of any lessons learned associated with the *Reportable Cyber Security Incident*.~~



~~**Figure 1: CIP-008-5 R3 Timeline for Reportable Cyber Security Incidents**~~

~~The activities necessary to complete the lessons learned include updating the plan and distributing those updates. Entities should consider meeting with all of the individuals involved in the incident and documenting the lessons learned as soon after the incident as possible. This allows more time for making effective updates to the plan, obtaining any necessary approvals, and distributing those updates to the incident response team.~~

~~The plan change requirement in Part 3.2 is associated with organization and technology changes referenced in the plan and involves the activities illustrated in Figure 2, below. Organizational changes include changes to the roles and responsibilities people have in the plan or changes to the response groups or individuals. This may include changes to the names or contact information listed in the plan. Technology changes affecting the plan may include referenced information sources, communication systems or ticketing systems.~~



~~**Figure 2: Timeline for Plan Changes in 3.2**~~

~~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 implementation of an effective Cyber Security Incident response plan mitigates the risk to the reliable operation of the BES caused as the result of a Cyber Security Incident and provides feedback to Responsible Entities for improving the security controls applying to BES Cyber Systems. Preventative activities can lower the number of incidents, but not all incidents can be prevented. A preplanned incident response capability is therefore necessary for rapidly detecting incidents, minimizing loss and destruction, mitigating the weaknesses that were exploited, and restoring computing services. An enterprise or single incident response plan for all BES Cyber Systems may be used to meet the Requirement. An organization may have a common plan for multiple registered entities it owns.~~

~~**Summary of Changes:** Wording changes have been incorporated based primarily on industry feedback to more specifically describe required actions.~~

~~**Reference to prior version:** (Part 1.1) CIP-008, R1.1~~

~~**Change Description and Justification:** (Part 1.1)~~

~~*"Characterize" has been changed to "identify" for clarity. "Response actions" has been changed to "respond to" for clarity.*~~

~~**Reference to prior version:** (Part 1.2) CIP-008, R1.1~~

~~**Change Description and Justification:** (Part 1.2)~~

~~*Addresses the reporting requirements from previous versions of CIP-008. This requirement part only obligates entities to have a process for determining Reportable Cyber Security Incidents. Also addresses the directive in FERC Order No. 706, paragraphs 673 and 676 to report within one hour (at least preliminarily).*~~

Reference to prior version: (Part 1.3) CIP-008, R1.2

Change Description and Justification: (Part 1.3)

Replaced incident response teams with incident response "groups or individuals" to avoid the interpretation that roles and responsibilities sections must reference specific teams.

Reference to prior version: (Part 1.4) CIP-008, R1.2

Change Description and Justification: (Part 1.4)
Conforming change to reference new defined term Cyber Security Incidents.

Rationale for R2:

The implementation of an effective Cyber Security Incident response plan mitigates the risk to the reliable operation of the BES caused as the result of a Cyber Security Incident and provides feedback to Responsible Entities for improving the security controls applying to BES Cyber Systems. This requirement ensures implementation of the response plans. Requirement Part 2.3 ensures the retention of incident documentation for post event analysis.

This requirement obligates entities to follow the Cyber Security Incident response plan when an incident occurs or when testing, but does not restrict entities from taking needed deviations from the plan. It ensures the plan represents the actual response and does not exist for documentation only. If a plan is written at a high enough level, then every action during the response should not be subject to scrutiny. The plan will likely allow for the appropriate variance in tactical decisions made by incident responders. Deviations from the plan can be documented during the incident response or afterward as part of the review.

Summary of Changes: Added testing requirements to verify the Responsible Entity's response plan's effectiveness and consistent application in responding to a Cyber Security Incident(s) impacting a BES Cyber System.

Reference to prior version: (Part 2.1) CIP-008, R1.6

Change Description and Justification: (Part 2.1)

Minor wording changes; essentially unchanged.

Reference to prior version: (Part 2.2) CIP-008, R1.6

Change Description and Justification: (Part 2.2)

Allows deviation from plan(s) during actual events or testing if deviations are recorded for review.

Reference to prior version: (Part 2.3) CIP-008, R2

Change Description and Justification: (Part 2.3)

~~*Removed references to the retention period because the Standard addresses data retention in the Compliance Section.*~~

~~**Rationale for R3:**~~

~~Conduct sufficient reviews, updates and communications to verify the Responsible Entity's response plan's effectiveness and consistent application in responding to a Cyber Security Incident(s) impacting a BES Cyber System. A separate plan is not required for those requirement parts of the table applicable to High or Medium Impact BES Cyber Systems. If an entity has a single Cyber Security Incident response plan and High or Medium Impact BES Cyber Systems, then the additional requirements would apply to the single plan.~~

~~**Summary of Changes:** Changes here address the FERC Order 706, Paragraph 686, which includes a directive to perform after-action review for tests or actual incidents and update the plan based on lessons learned. Additional changes include specification of what it means to review the plan and specification of changes that would require an update to the plan.~~

~~**Reference to prior version:** (Part 3.1) CIP-008, R1.5~~

~~**Change Description and Justification:** (Part 3.1)~~

~~*Addresses FERC Order 706, Paragraph 686 to document test or actual incidents and lessons learned.*~~

~~**Reference to prior version:** (Part 3.2) CIP-008, R1.4~~

~~**Change Description and Justification:** (Part 3.2)~~

~~*Specifies the activities required to maintain the plan. The previous version required entities to update the plan in response to any changes. The modifications make clear the changes that would require an update.*~~

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		Updated version number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	Update
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-008-5.	
5	7/9/14	FERC Letter Order issued approving VRFs and VSLs revisions to certain CIP standards.	CIP-008-5 Requirement R2, VSL table under Severe, changed from 19 to 18 calendar months.
6	~~10/4/18~~TBD	Modified to address directives in FERC Order No. 848	

CIP-008-6 – Attachment 1

Cyber Security Incident Reporting Form

Use this form to report Reportable Cyber Security Incidents and Reportable Attempted Cyber Security Incidents in accordance with CIP-008-6, Requirement R4.

Contact Information	
Name:	
Phone Number:	

Incident Type

- ☐ Reportable Cyber Security Incident
- ☐ Reportable Attempted Cyber Security Incident

Reporting Category

- ☐ Initial Notification
- ☐ Update

Required Attribute Information

1. Attack Vector	☐ Initial	☐ Update
2. Functional Impact	☐ Initial	☐ Update
3. Level of Intrusion	☐ Initial	☐ Update

CIP-008-6 – Attachment 2

Cyber Security Incident Reporting Form Instructions

Attachment 2 provides instructions to aid in the completion of Attachment 1.

CIP-008-6—Reportable Cyber Security Incident Reporting Form Instructions		
Form Section	**Field Name**	**Instructions**
Contact Information	**Name**	Enter the First and Last Name of the Responsible Entity's primary point of contact for the reported incident.
	Phone Number	Enter the Phone Number(s) of the Responsible Entity's primary point of contact for the reported incident.
Incident Type	**Reportable Cyber Security Incident**	Check this box if Attachment 1 includes information for a Reportable Cyber Security Incident.
	Reportable Attempted Cyber Security Incident	Check this box if Attachment 1 includes information for a Reportable Attempted Cyber Security Incident. Note: Do not check this box for incidents related solely to a PSP(s).
Reporting Category	**Initial Notification**	Check this box if Attachment 1 is being submitted to satisfy initial notification obligations of Requirement R4 Part 4.2.
	Update	Check this box if Attachment 1 is being submitted to satisfy subsequent follow-up or update obligations of Requirement R4 Part 4.2.
Required Attribute Information (Attack Vector fields)	**Attack Vector**	• If known, enter a narrative description of the Attack Vector for the compromise or attempt to compromise to satisfy the required attribute specified in Requirement R4 Part 4.1. • If not known, specify 'unknown' in the field. *Examples include, but are not limited to, malware, use of stolen credentials, etc.*
	Attack Vector Initial Checkbox	If Attachment 1 is being used to provide the preliminary report, select the 'Initial' checkbox.
	Attack Vector Update Checkbox	If Attachment 1 is being used to provide an update report, select the 'Update' checkbox.

CIP-008-6 – Reportable Cyber Security Incident Reporting Form Instructions		
Form Section	**Field Name**	**Instructions**
Required Attribute Information (Functional Impact fields)	**Functional Impact**	• If known, enter a narrative description of the functional impact for the compromise or attempt to compromise to satisfy the required attribute specified in Requirement R4 Part 4.1. • If not known, specify 'unknown' in the field. *Examples include, but are not limited to, situational awareness, dynamic response, ability to perform Real-time Assessments, or Real-time monitoring etc.*
	Functional Impact Initial Checkbox	If Attachment 1 is being used to provide the preliminary report, select the 'Initial' checkbox.
	Functional Impact Update Checkbox	If Attachment 1 is being used to provide an update report, select the 'Update' checkbox.
Required Attribute Information (Level of Intrusion fields)	**Level of Intrusion**	• If known, enter a narrative description of the level of intrusion for the compromise or attempt to compromise to satisfy the required attribute specified in Requirement R4 Part 4.1. • If not known, specify 'unknown' in the field. *Examples include, but are not limited to, whether the compromise or attempt to compromise occurred on Applicable Systems outside the Electronic Security Perimeter (ESP), at the ESP, or inside the ESP. Additionally, level of intrusion may include the Applicable System impact level and Cyber Asset classification level.*
	Level of Intrusion Initial Checkbox	If Attachment 1 is being used to provide the preliminary report, select the 'Initial' checkbox.
	Level of Intrusion Update Checkbox	If Attachment 1 is being used to provide an update report, select the 'Update' checkbox.

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Implementation Plan

Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting | Reliability Standard CIP-008-6

Applicable Standard

- CIP-008-6 – Cyber Security – Incident Reporting and Response Planning

Requested Retirement

- CIP-008-5 – Cyber Security – Incident Reporting and Response Planning

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective: None

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

New Terms in the NERC Glossary of Terms

This section includes all newly defined, revised, or retired terms used or eliminated in the NERC Reliability Standard. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the *Glossary of Terms Used in NERC Reliability Standards.*~~Glossary.~~

~~**Proposed New Definition:**~~
~~Reportable Attempted Cyber Security Incident:~~
~~A Cyber Security Incident that was determined by the Responsible Entity to be an attempt to compromise or disrupt:~~

- ~~A BES Cyber Asset(s) that perform One or more reliability tasks of a functional entity; or~~
- ~~Electronic Security Perimeter(s); or~~

- ~~Electronic Access Control or Monitoring Systems. (EACMS) that provide any of the following functions: (1) authentication; (2) monitoring and logging; (3) access control; (4) Interactive Remote Access; or (5) alerting~~

Proposed Modified Definitions:
Cyber Security Incident:
A malicious act or suspicious event that:

- Compromises, or was an attempt to compromise the, (1) ~~the~~ Electronic Security Perimeter, ~~or~~ (2) Physical Security Perimeter, ~~or~~ (3) Electronic Access Control or Monitoring Systems for High or Medium Impact BES Cyber Systems; ~~,~~ or
- Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System.

Reportable Cyber Security Incident:
A Cyber Security Incident that has compromised or disrupted:

- A BES Cyber System ~~Asset(s)~~ that performs ~~O~~one or more reliability tasks of a functional entity; ~~or~~
- Electronic Security Perimeter(s); or
- Electronic Access Control or Monitoring Systems. ~~(EACMS) that provide any of the following functions: (1) authentication; (2) monitoring and logging; (3) access control; (4) Interactive Remote Access; or (5) alerting~~

Proposed Retirements of Approved Definitions:
Cyber Security Incident:
A malicious act or suspicious event that:

- Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter or,
- Disrupts, or was an attempt to disrupt, the operation of a BES Cyber system.

Reportable Cyber Security Incident:
A Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity.

Background

The purpose of this project is to address the directives issued by FERC in Order No. 848 to augment mandatory reporting of Cyber Security Incidents, including attempted Cyber Security Incidents that might facilitate subsequent efforts to harm the R~~r~~eliable O~~o~~peration of the Bulk Electric System (BES). FERC directed NERC to develop and submit modifications that would "require the reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's Electronic Security Perimeter (ESP) or associated Electronic Access Control or Monitoring Systems (EACMS)." (Order No. 848 at P1)

Proposed Reliability Standard CIP-008-6 addresses the 4 elements outlined by FERC:

1. Responsible entities must report Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS;
2. Required information in Cyber Security Incident reports should include certain minimum information to improve the quality of reporting and allow for ease of comparison by ensuring that each report includes specified fields of information;
3. Establish deadlines for filing Cyber Security Incidents that are commensurate with incident severity; and
4. Cyber Security Incident reports should be sent to the Electricity Information Sharing and Analysis Center (E-ISAC) and the Department of Homeland Security (DHS) Industrial Control Systems Cyber Emergency Response Team (ICS-CERT).

Effective Date

Reliability Standard CIP-008-6

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 18~~12~~ calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

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

Definition

Where approval by an applicable governmental authority is required, the definition shall become effective on the first day of the first calendar quarter that is 18~~12~~ calendar months after the effective date of the applicable governmental authority's order approving Reliability Standard CIP-008-6, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter that is 18~~12~~ calendar months after the date that Reliability Standard CIP-008-6 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard CIP-008-5

Reliability Standard CIP-008-5 shall be retired immediately prior to the effective date of Reliability Standard CIP-008-6 in the particular jurisdiction in which the revised standard is becoming effective.

Definition

The definitions proposed for retirement shall be retired immediately prior to the effective date of Reliability Standard CIP-008-6 in the particular jurisdiction in which the revised standard is becoming effective.

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DRAFT

Cyber Security – Incident Reporting

Technical Rationale and Justification for Reliability Standard CIP-008-6

November 2018

RELIABILITY | ACCOUNTABILITY






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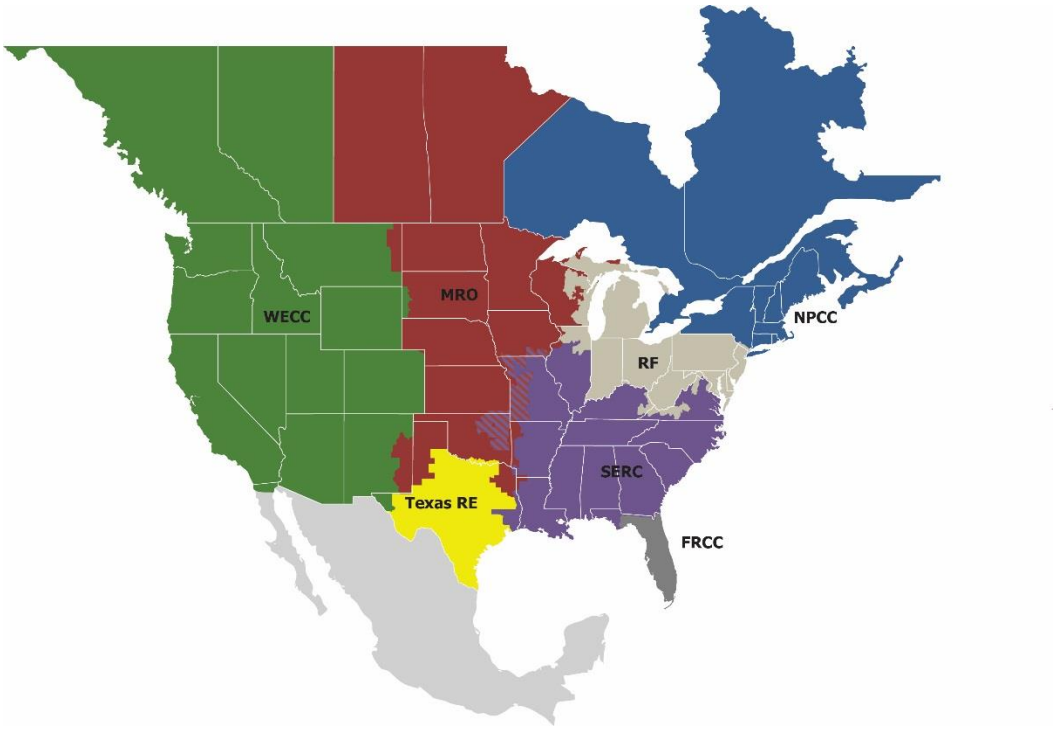
Table of Contents

Preface iii
Introduction 1
New and Modified Terms Used in NERC Reliability Standards 2
Proposed Modified Terms: 2
Cyber Security Incident 2
Reportable Cyber Security Incident 2
EACMS 2
Requirements R1, R2, and R3 2
General Considerations for Requirement R1, Requirement R2, and Requirement R3 2
Moving Parts of Requirement R1 to Requirement R4 3
Inclusion of "Successor Organizations" throughout the Requirement Parts 3
Requirement R4 3
General Considerations for Requirement R4 3
Required Reportable Incident Attributes 3
Methods for Submitting Notifications 3
Notification Timing 4
Notification Updates 5
CIP-008 Version History from Guidelines and Technical Basis 6

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 document explains the technical rationale and justification for the proposed Reliability Standard CIP-008-6. It provides stakeholders and the ERO Enterprise with an understanding of the technology and technical requirements in the Reliability Standard. It also contains information on the Standard Drafting Team's (SDT's) intent in drafting the requirements. This Technical Rationale and Justification for CIP-008-6 is not a Reliability Standard and should not be considered mandatory and enforceable.

On July 19, 2018, the Federal Energy Regulatory Commission (FERC or Commission) issued Order No. 848. In this Order FERC directed the North American Electric Reliability Corporation (NERC) to "develop and submit modifications to the Reliability Standards to require the reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's Electronic Security Perimeter (ESP) or associated Electronic Access and Control or Monitoring System (EACMS)." (Order 848, Paragraph 1)

In response to the directive in Order No. 848, the Project 2018-02 SDT drafted Reliability Standard CIP-008-6 to require Responsible Entities to implement methods augmenting the mandatory reporting of Cyber Security Incidents to include: "(1) responsible entities must report Cyber Security incidents that compromise, or attempt to compromise, a responsible entity's ESP; (2) required information in Cyber Security Incident reports should include certain minimum information to improve the quality of reporting and allow for ease of comparison by ensuring that each report included specified fields of information; (3) filing deadlines for Cyber Security Incident reports should be established once a compromise or disruption to reliable BES operation, or an attempted compromise or disruption, is identified by a responsible entity; and (4) Cyber Security Incident reports should continue to be sent to the Electricity Information Sharing and Analysis Center (E-ISAC), rather than the Commission, but the reports should also be sent to the Department of Homeland Security (DHS) Industrial Control System Cyber Emergency Response Team (ICS-CERT)." (Order 848, Paragraph 3)

New and Modified Terms Used in NERC Reliability Standards

Proposed Modified Terms:

Cyber Security Incident

A malicious act or suspicious event that:

- *Compromises, or was an attempt to compromise the, (1) the Electronic Security Perimeter, (2) Physical Security Perimeter, (3) Electronic Access Control or Monitoring Systems for High or Medium Impact BES Cyber Systems or;*
- *Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System.*

In response to FERC Order 848, Paragraph 1, the SDT modified the Cyber Security Incident definition to included Electronic Access Control or Monitoring Systems (EACMS) in response to the Order.

The addition of High and Medium Impact BES Cyber Systems considers the potential unintended consequences with the use of the existing definition in CIP-003-7. It also assures clarity and the intent to exclude Low Impact from the definition.

Reportable Cyber Security Incident

A Cyber Security Incident that has compromised or disrupted:

- *A BES Cyber System that performs one or more reliability tasks of a functional entity;*
- *Electronic Security Perimeter(s); or*
- *Electronic Access Control or Monitoring System.*

The Reportable Cyber Security Incident definition was modified to comply with FERC Order 848. In response to Paragraph 54 of the Order, the SDT modified the definition to include incidents that compromised or disrupted an ESP or an EACMS. The team also added the qualifying clause for A BES Cyber System "that performs one or more reliability tasks of a functional entity" to clarify what was compromised or disrupted, thus not extending the scope to Protected Cyber Assets (PCAs).

EACMS

The drafting team spent significant time discussing this topic through industry outreach, among the team, and with FERC staff. The team believes by not specifically referencing the 5 functions in the Order, we have reduced complexity and made compliance with the Standard achievable. The drafting team asserts that the five functions are equivalent to the current definition of EACMS in the NERC Glossary of Terms. If entities have questions about application of the EACMS definition, the drafting team advises that entities please discuss those questions directly with NERC.

Requirements R1, R2, and R3

General Considerations for Requirement R1, Requirement R2, and Requirement R3

FERC Order 848, Paragraph 1, directs modifications to Reliability Standards to require reporting of incidents that compromise, or attempt to compromise a responsible entity's ESP or associated EACMS. The intent of the SDT was

to minimize the changes within CIP-008 and address the required changes. To do this, the SDT added "and their associated EACMS" to the "Applicable Systems" column for Requirements R1, R2, and R3.

To add clarity to "attempts to compromise," the drafting team created Part 1.2.1 to require entities to establish and document their process for defining attempts to compromise. This requirement maps to Requirement 4 Part 4.2, which requires entities to use that entity-defined criteria for determining which incidents entities must report.

The use of the language regarding Cyber Security Incident(s) being "only an attempt to compromise one or more systems identified in the "Applicable Systems" column for the Part is meant to clarify the assets for which entities are required to report attempts. This language is used throughout the standard.

Moving Parts of Requirement R1 to Requirement R4

To minimize the changes to Requirement R1, the SDT created Requirement R4 and consolidated all the CIP-008-6 reporting requirements. The SDT deleted the Requirement R1 Part 1.2 reporting requirements and moved them to Requirement R4 for this purpose.

Inclusion of "Successor Organizations" throughout the Requirement Parts

The SDT recognizes that organizations are constantly evolving to meet emerging needs, and may re-organize or change their names over time. The ICS-CERT has completed its name change to the National Cybersecurity and Communications Integration Center (NCCIC) Industrial Control Systems. The E-ISAC previously re-branded its name and may again in the future. By following Requirement R4 references to E-ISAC and NCCIC with "or their successors" the SDT is ensuring that Requirement R4 can be implemented even if the names of E-ISAC and NCCIC change or a different agency takes over their current role.

Requirement R4

General Considerations for Requirement R4

Requirement R4 is a new requirement focused on mandatory reporting of Reportable Cyber Security Incidents and newly-defined Reportable Attempted Cyber Security Incidents (refer to Proposed New Term, above). Previously, CIP-008-5 defined reporting requirements for Reportable Cyber Security Requirements (Requirement R1 Part 1.2) only.

Required Reportable Incident Attributes

Requirement R4.1 specifies that initial notifications and updates must include three attributes: 1) functional impact, 2) attack vector used, and 3) level of intrusion achieved or attempted. These attributes are taken directly from the Order. (FERC Order No. 848, paragraph 89).

The SDT understands that some or all of these attributes may be unknown at time of initial notification. To address that, it added "to the extent known" to account for this scenario. There is an expectation that update reporting will be done as new information is determined by the entity to fill-in unknown attributes.

Methods for Submitting Notifications

Requirement R4 Part 4.2 allows responsible entities to submit notification using any approved method supported by E-ISAC and NCCIC. The SDT provided some latitude in reporting methods and format to allow responsible entities' personnel to focus on incident response itself and not the methods and format of reporting. It is important to note the report must contain the three attributes required in Requirement R4 Part 4.1 as they are known.

Notification Timing

Requirement R4 Part 4.2 specifies two timelines for initial notification submission; one hour for Reportable Cyber Security Incidents; and end of next calendar day for Reportable Attempted Cyber Security Incidents. Paragraph 3 of FERC Order No 848 directly states that reporting deadlines must be established. Paragraph 89 further states that "timelines that are commensurate with the adverse impact to the BES that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES."

- *Reportable Cyber Security Incidents* – The SDT wrote Requirement R4 Part R4.2 to use a one hour deadline for reporting of these events because incidents in this category include successful penetrations of ESP(s), EACMS, or BES Cyber Asset(s). One hour is referenced directly in FERC Order No 848 paragraph 89 and is also the current reporting requirement in CIP-008-5.
- *Cyber Security Incident that was only an attempt to compromise one or more systems identified in the "Applicable Systems" column* - Due to the lower severity of these unsuccessful attempts at penetrating ESP(s), EACMS, or BES Cyber Asset(s), the SDT proposed a longer reporting timeframe. The intent behind the decision to add "By the end of the next calendar day (11:59 pm local time)" was to give responsible entities additional time to gather facts prior to notifications for the less severe attempts to compromise Applicable Systems.

The SDT understands initial notification may not have all the details when first submitted. It is expected, however, that information that has been determined is reported within the notification deadlines. Additionally, it is important to note the wording in Requirement R4 Part 4.2. The intent was for the timing of reporting to begin after the Responsible Entity has determined that the incident meets the reporting threshold.

Technical rationale taken from the Guidelines and Technical Basis (GTB) CIP-008-5 Requirement 1 provides additional justification for the SDT to maintain the one hour timeframe for Reportable Cyber Security Incidents.

> *The reporting obligations for Reportable Cyber Security Incidents require at least a preliminary notice to the ES-ISAC within one hour after determining that a Cyber Security Incident is reportable (not within one hour of the Cyber Security Incident, an important distinction). This addition is in response to the directive addressing this issue in FERC Order No. 706, paragraphs 673 and 676, to report within one hour (at least preliminarily). This standard does not require a complete report within an hour of determining that a Cyber Security Incident is reportable, but at least preliminary notice, which may be a phone call, an email, or sending a Web-based notice. The standard does not require a specific timeframe for completing the full report.*

Back in 2007, the Electricity Information Sharing and Analysis Center (E-ISAC) was known as the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). Its voluntary procedures required the reporting of a cyber-incident within one hour of an incident. CIP-008-1 required entities to report to the ES-ISAC.

In FERC Order No. 706[1] (July 18, 2008), the Commission concluded that the one-hour reporting limit was reasonable [P 663]. The Commission further stated that it was leaving the details to NERC, but it wanted the reporting timeframe to run from the "**discovery**" of the incident by the entity, and not the actual **"occurrence"** of the incident [P 664].

CIP-008-2 and CIP-008-3 were silent regarding the required timeframe for reporting, but it was specifically addressed in CIP-008-5. In the October 26, 2012, redlined version of CIP-008-5, the proposed language for initial notification originally specified "one hour from **identification**" of an incident. This aligned with the Commission's decision in Order No. 706, for the clock to start with the discovery of an incident. However, the Standard Drafting Team changed "one

[1] 2008, Federal Energy Regulatory Commission, Mandatory Reliability Standards for Critical Infrastructure Protection, Order No. 706.

hour from identification" to "one hour from the **determination** of a Reportable Cyber Security Incident". This language was subsequently approved and incorporated into CIP-008-5.

These changes, from "occurrence" to "discovery" to "determination," provide the additional time needed for the entity to apply its specifically created process(es) for determining whether a Cyber Security Incident rises to the level of required reporting. This determination timeframe may include a preliminary investigation of the incident which will provide useful information to other entities to help defend against similar attacks.

Notification Updates

Requirement R4 Part 4.3 requires that Responsible Entities submit updates for the required attributes upon determination of new or changed attribute information. The SDT added this language to provide entities sufficient time to determine attribute information, which may be unknown at the time of initial notification, and which may change as more information is gathered. The intent of Requirement R4 Part 4.3 is to provide a method for responsible entities to report new information over time as investigations progress. NOTE: The SDT does not intend updates specified in Requirement R4. Part 4.3 to expose responsible entities to potential violations if, for example, initial and updated notification on the same attribute have different information. This is expected since knowledge of attributes may change as investigations proceed. Rather, the intent of Requirement R4 Part 4.3 is to have a mechanism to report incident information to E-ISAC and NCCIC (ICS-CERT), or their successors, (and industry) upon determination of each required attribute.

The entity's process for reporting should contain a step to report until such time the entity has determined the investigation process has concluded. This allows a "closure" of this incident. At this time there is a possibility that because of circumstances, i.e. a Cyber Asset was restored completely, removing all forensic evidence in order to restore operations, which caused the entity to conclude its investigation without having a complete knowledge of the three required attributes. In this circumstance the intent is that the entity report what is known and document the reason not all attributes could be reported.

The SDT asserts that nothing included in the new reporting Requirement R4, precludes the entity from continuing to provide any voluntary sharing they may already be conducting today.

CIP-008 Version History from Guidelines and Technical Basis

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

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

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

Requirement R1:

The reporting obligations for Reportable Cyber Security Incidents require at least a preliminary notice to the ES-ISAC within one hour after determining that a Cyber Security Incident is reportable (not within one hour of the Cyber Security Incident, an important distinction). This addition is in response to the directive addressing this issue in FERC Order No. 706, paragraphs 673 and 676, to report within one hour (at least preliminarily). This standard does not require a complete report within an hour of determining that a Cyber Security Incident is reportable, but at least preliminary notice, which may be a phone call, an email, or sending a Web-based notice. The standard does not require a specific timeframe for completing the full report.

Requirement R2:

Requirement R2 ensures entities periodically test the Cyber Security Incident response plan. This includes the requirement in Part 2.2 to ensure the plan is actually used when testing. The testing requirements are specifically for Reportable Cyber Security Incidents.

Entities may use an actual response to a Reportable Cyber Security Incident as a substitute for exercising the plan annually. Otherwise, entities must exercise the plan with a paper drill, tabletop exercise, or full operational exercise.

In addition to the requirements to implement the response plan, Part 2.3 specifies entities must retain relevant records for Reportable Cyber Security Incidents. There are several examples of specific types of evidence listed in the measure.

Requirement R3:

This requirement ensures entities maintain Cyber Security Incident response plans. There are two requirement parts that trigger plan updates: (1) lessons learned from Part 3.1 and (2) organizational or technology changes from Part 3.2.

The documentation of lessons learned from Part 3.1 is associated with each Reportable Cyber Security Incident and involves the activities as illustrated in Figure 1, below. The deadline to document lessons learned starts after the completion of the incident in recognition that complex incidents on complex systems can take a few days or weeks to complete response activities. It is possible to have a *Reportable Cyber Security Incident* without any documented lessons learned. In such cases, the entity must retain documentation of the absence of any lessons learned associated with the *Reportable Cyber Security Incident*.

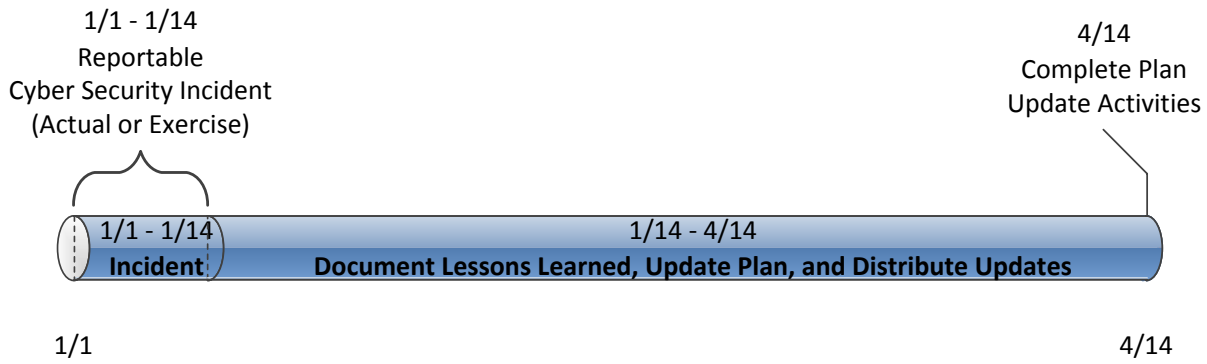
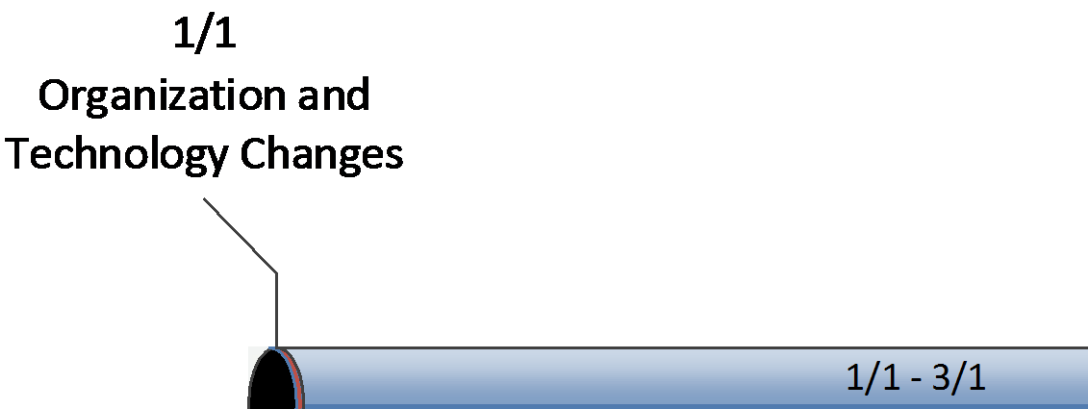


Figure 1: CIP-008-5 R3 Timeline for Reportable Cyber Security Incidents

The activities necessary to complete the lessons learned include updating the plan and distributing those updates. The plan change requirement in Part 3.2 is associated with organization and technology changes referenced in the plan and involves the activities illustrated in Figure 2, below. Organizational changes include changes to the roles and responsibilities people have in the plan or changes to the response groups or individuals.

Figure 2: Timeline for Plan Changes in 3.2



Rationale for R1:
The implementation of an effective Cyber Security Incident response plan mitigates the risk to the reliable operation of the BES caused as the result of a Cyber Security Incident and provides feedback to Responsible Entities for improving the security controls applying to BES Cyber Systems. Preventative activities can lower the number of incidents, but not all incidents can be prevented. A preplanned incident response capability is therefore necessary for rapidly detecting incidents, minimizing loss and destruction, mitigating the weaknesses that were exploited, and restoring computing services.

Summary of Changes: Wording changes have been incorporated based primarily on industry feedback to more specifically describe required actions.

Reference to prior version: (Part 1.1) CIP-008, R1.1

Change Description and Justification: (Part 1.1)

"Characterize" has been changed to "identify" for clarity. "Response actions" has been changed to "respond to" for clarity.

Reference to prior version: (Part 1.2) CIP-008, R1.1

Change Description and Justification: (Part 1.2)

Addresses the reporting requirements from previous versions of CIP-008. This requirement part only obligates entities to have a process for determining Reportable Cyber Security Incidents. Also addresses the directive in FERC Order No. 706, paragraphs 673 and 676 to report within one hour (at least preliminarily).

Reference to prior version: (Part 1.3) CIP-008, R1.2

Change Description and Justification: (Part 1.3)

Replaced incident response teams with incident response "groups or individuals" to avoid the interpretation that roles and responsibilities sections must reference specific teams.

Reference to prior version: (Part 1.4) CIP-008, R1.2

Change Description and Justification: (Part 1.4)
Conforming change to reference new defined term Cyber Security Incidents.

Rationale for R2:
The implementation of an effective Cyber Security Incident response plan mitigates the risk to the reliable operation of the BES caused as the result of a Cyber Security Incident and provides feedback to Responsible Entities for improving the security controls applying to BES Cyber Systems. This requirement ensures implementation of the response plans. Requirement Part 2.3 ensures the retention of incident documentation for post event analysis.
This requirement obligates entities to follow the Cyber Security Incident response plan when an incident occurs or when testing, but does not restrict entities from taking needed deviations from the plan. It ensures the plan represents the actual response and does not exist for documentation only.
Summary of Changes: Added testing requirements to verify the Responsible Entity's response plan's effectiveness and consistent application in responding to a Cyber Security Incident(s) impacting a BES Cyber System.

Reference to prior version: (Part 2.1) CIP-008, R1.6

Change Description and Justification: (Part 2.1)

Minor wording changes; essentially unchanged.

Reference to prior version: (Part 2.2) CIP-008, R1.6

Change Description and Justification: (Part 2.2)

Allows deviation from plan(s) during actual events or testing if deviations are recorded for review.

Reference to prior version: (Part 2.3) CIP-008, R2

Change Description and Justification: (Part 2.3)
Removed references to the retention period because the Standard addresses data retention in the Compliance Section.

Rationale for R3:
Conduct sufficient reviews, updates and communications to verify the Responsible Entity's response plan's effectiveness and consistent application in responding to a Cyber Security Incident(s) impacting a BES Cyber System. A separate plan is not required for those requirement parts of the table applicable to High or Medium Impact BES Cyber Systems. If an entity has a single Cyber Security Incident response plan and High or Medium Impact BES Cyber Systems, then the additional requirements would apply to the single plan.
Summary of Changes: Changes here address the FERC Order 706, Paragraph 686, which includes a directive to perform after-action review for tests or actual incidents and update the plan based on lessons learned. Additional changes include specification of what it means to review the plan and specification of changes that would require an update to the plan.

Reference to prior version: (Part 3.1) CIP-008, R1.5

Change Description and Justification: (Part 3.1)

Addresses FERC Order 706, Paragraph 686 to document test or actual incidents and lessons learned.

Reference to prior version: (Part 3.2) CIP-008, R1.4

Change Description and Justification: (Part 3.2)

Specifies the activities required to maintain the plan. The previous version required entities to update the plan in response to any changes. The modifications make clear the changes that would require an update

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Violation Risk Factor and Violation Severity Level Justification

Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in CIP-008-6~~[Project Number and Name or Standard Number]~~. 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 CIP-008-6, Requirement R1
The VRF did not change from the previously FERC-approved CIP-008-5 Reliability Standard.

VSL Justification for CIP-008-6, Requirement R1
The justification is provided on the following pages.

VRF Justification for CIP-008-6, Requirement R2
The VRF did not change from the previously FERC-approved CIP-008-5 Reliability Standard.

VSL Justification for CIP-008-6, Requirement R2
The VSL did not substantively change from the previously FERC-approved CIP-008-5 Reliability Standard. Only minor revisions were made.

VRF Justification for CIP-008-6, Requirement R3
The VRF did not change from the previously FERC-approved CIP-008-5 Reliability Standard.

VSL Justification for CIP-008-6, Requirement R3
The VSL did not change from the previously FERC-approved CIP-008-5 Reliability Standard.

VRF Justification for CIP-008-6, Requirement R4
The justification is provided on the following pages.

VSL Justification for CIP-008-6, Requirement R4
The justification is provided on the following pages.

VSLs for CIP-008-6, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Responsible Entity has developed the Cyber Security Incident response plan(s), but the plan does not include the roles and responsibilities of Cyber Security Incident response groups or individuals. (1.3) OR The Responsible Entity has developed the Cyber Security Incident response plan(s), but the plan does not include incident handling procedures for Cyber Security Incidents. (1.4) OR The Responsible Entity has developed a Cyber Security Incident response plan, but the plan does not include one or more processes to provide notification per Requirement R4. (1.2) OR The Responsible Entity has developed a Cyber Security Incident response plan, but the plan does not include one or more processes to establish	The Responsible Entity has not developed a Cyber Security Incident response plan with one or more processes to identify, classify, and respond to Cyber Security Incidents. (1.1) OR The Responsible Entity has developed a Cyber Security Incident response plan, but the plan does not include one or more processes to identify Reportable Cyber Security Incidents or a Cyber Security Incident that was only an attempt to compromise a system identified in the "Applicable Systems" column for Part 1.2. (1.2)

VSLs for CIP-008-6, Requirement R1			
Lower	Moderate	High	Severe
		criteria to evaluate and define attempts to compromise. (1.2)	

VSL Justifications for CIP-008-6, Requirement R1	
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 CIP-008-5 and add two VSLs to the High and Severe categories to reflect new subparts 1.2.1 and 1.2.3. The two new VSLs are similar to currently-approved VSLs. 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.

VSL Justifications for CIP-008-6, Requirement R1	
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 CIP-008-6, Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is being proposed for this requirement. ~~The VRF is being established for this requirement.~~ A VRF of lower is appropriate due to the fact that the requirement is associated with reporting obligations, not response to Cyber Security Incident(s), Reportable Cyber Security Incident(s), or Reportable Attempted Cyber Security Incident(s). If violated, is administrative and would not be expected to adversely affect the electrical state or capability of the bulk electric system.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	N/A
FERC VRF G3 Discussion	The proposed VRF is consistent among other FERC approved VRF's within the standard.

VRF Justifications for CIP-008-6, Requirement R4	
Proposed VRF	**Lower**
Guideline 3- Consistency among Reliability Standards	
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The team relied on NERC's definition of lower risk requirement.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	Failure to report would not, under Emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

VSLs for CIP-008-6, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity notified E-ISAC and NCCIC, or their successors, of a Cyber Security Incident that was only an attempt to compromise a system identified in the "Applicable Systems" column for Part 4.2 but failed to notify or update E-ISAC or NCCIC, or their successors, within the timelines	The Responsible Entity failed to notify E-ISAC or NCCIC, or their successors, of a Cyber Security Incident that was only an attempt to compromise a system identified in the "Applicable Systems" column. (R4)	The Responsible Entity notified E-ISAC and ~~ICS-CERT~~NCCIC, or their successors, of a Reportable Cyber Security Incident but failed to notify or update E-ISAC or ~~ICS-CERT~~NCCIC, or their successors, within the ~~timeframes~~ timelines pursuant	The Responsible Entity failed to notify E-ISAC ~~or~~ and ~~ICS-CERT~~NCCIC, or their successors, of a Reportable Cyber Security Incident ~~or Reportable Attempted Cyber Security Incident~~. (R4)

VSLs for CIP-008-6, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
pursuant to Requirement R4, Part 4.2. (4.2) OR The Responsible Entity notified E-ISAC and NCCIC, or their successors, of a Reportable Cyber Security Incident or a Cyber Security Incident that was only an attempt to compromise a system identified in the "Applicable Systems" column for Part 4.3 but failed to report on one or more of the attributes within 7 days after determination of the attribute(s) not reported pursuant to Requirement R4, Part 4.1. (4.3) OR The Responsible Entity notified E-ISAC and NCCIC, or their successors, of a Reportable Cyber Security Incident or a Cyber Security Incident that was only an attempt to compromise a system identified in the "Applicable Systems" column for Part 4.1 but failed to report on one or more of the attributes	~~The Responsible Entity notified E-ISAC and ICS-CERT, or their successors, of a Reportable Cyber Security Incident or Reportable Attempted Cyber Security Incident but failed to report on one or more of the attributes within the timeframes pursuant to Requirement R4, Part 4.4 after determination of the attribute(s) not reported pursuant to Requirement R4, Part 4.1. (4.4)~~ ~~OR~~ ~~The Responsible Entity notified E-ISAC and ICS-CERT, or their successors, of a Reportable Cyber Security Incident or Reportable Attempted Cyber Security Incident but failed to report on one or more of the attributes after determination of the attribute pursuant to Requirement R4, Part 4.1.~~	to Requirement R4, Part 4.2~~3~~. (4.2) OR The Responsible Entity failed to notify E-ISAC or NCCIC, or their successors, of a Reportable Cyber Security Incident. (R4)	

VSLs for CIP-008-6, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
after determination pursuant to Requirement R4, Part 4.1. (4.1) ~~The Responsible Entity notified E-ISAC and ICS-CERT, or their successors, of a Reportable Cyber Security Incident or Reportable Attempted Cyber Security Incident and the attributes within the timeframes pursuant to Requirement R4, Parts 4.1 and 4.3 but failed to submit the form in Attachment 1. (4.4)~~ ~~OR~~ ~~The Responsible Entity notified E-ISAC and ICS-CERT, or their successors, of a Reportable Cyber Security Incident or Reportable Attempted Cyber Security Incident and the attributes within the timeframes pursuant to Requirement R4, Parts 4.1 and 4.3 but failed to use one of the methods for initial notification pursuant to Requirement R4, Part 4.2.~~			

VSL Justifications for CIP-008-6, Requirement R4	
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 does not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed 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 uses the same terminology as used in the associated requirement and isare, therefore, consistent with the requirement.

VSL Justifications for CIP-008-6, Requirement R4	
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.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DRAFT Implementation Guidance Pending Submittal for ERO Enterprise Endorsement

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Cyber Security – Incident Reporting and Response Planning

Implementation Guidance for CIP-008-6

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Table of Contents

Introduction 4

Definitions 5

Determination and Classification of Cyber Security Incidents 7

- Example of a Cyber Incident Classification Process 9
- Sample Classification Schema 10
- Examples of the use of the Sample Classification Schema 12

Attempts to Compromise and Cyber Security Incidents 18

- Examples of Cyber Security Incidents, attempts to compromise “Applicable Systems”, and Reportable Cyber Security Incidents 19
- Example of Sample Criteria to Evaluate and Define Attempts to Compromise 21

Requirement R1 23

- General Considerations for R1 23
- Implementation Guidance for R1 24
- Process to Identify, Classify, and Respond to Cyber Security Incidents (R1.1, R1.2) 24
- Supporting Narrative Description of Sample Process to Identify, Classify, and Respond to Cyber Security Incidents (R1.1, R1.2) 26
- Roles and Responsibilities (R1.3) 28
- Incident handling procedures for Cyber Security Incidents (R1.4) 30

Requirement R2 32

- General Considerations for R2 32
- Implementation Guidance for R2 33
- Acceptable Testing Methods 33

Requirement R3 34

- General Considerations for R3 34
- Implementation Guidance for R3 34

Requirement R4 35

- General Considerations for R4 35
- Implementation Guidance for R4 36
- NCCIC Reporting 36
- Example of a Reporting Form 37
- Instructions for Example of a Reporting Form 39

List of Figures

Figure 1 Relationship of Cyber Security Incidents 6
Figure 2 Potential Approach Tool 7
Figure 3 Flow Diagram for Cyber Security Incidents 8
Figure 4 Typical Infrastructure 9
Figure 5 Example of Classification Schema 11
Figure 6 Examples of the Use of the Classification Schema 15
Figure 7 Examples of Non-Reportable Cyber Incidents 16
Figure 8 Examples of Reportable Cyber Security Incidents or attempt to compromise one or more applicable systems 17
Figure 9 Examples of Cyber Security Incidents, attempts to compromise “Applicable Systems”, and Reportable Cyber Security Incidents 20
Figure 10 Sample Process to Identify, Classify and Respond to Cyber Security Incidents 25
Figure 11 NCCIC Reporting Attributes 36

Introduction

The Standards Project 2018-02 – Modifications to CIP-008 Standard Drafting Team (SDT) prepared this Implementation Guidance to provide example approaches for compliance with the modifications to CIP-008-6. 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 that better fit their individual situations.[1]

Responsible entities may find it useful to consider this Implementation Guidance document along with the additional context and background provided in the SDT-developed Technical Rationale and Justification for the modifications to CIP- 008-6.

The Federal Energy Regulatory Commission (the Commission) issued Order No. 848 on July 19, 2018, calling for modifications to the NERC Reliability Standards to augment the mandatory reporting of Cyber Security Incidents, including incidents that might facilitate subsequent efforts to harm the reliable operation of the BES.[2] The Commission directed the North American Electric Reliability Corporation (NERC) to develop and submit modifications to the Reliability Standards to require the reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's Electronic Security Perimeter (ESP) or associated Electronic Access Control or Monitoring Systems (EACMS).[3]

The Commission's directive consisted of four elements intended to augment the current Cyber Security Incident reporting requirement: (1) responsible entities must report Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS; (2) required information in Cyber Security Incident reports should include certain minimum information to improve the quality of reporting and allow for ease of comparison by ensuring that each report includes specified fields of information; (3) filing deadlines for Cyber Security Incident reports should be established once a compromise or disruption to reliable BES operation, or an attempted compromise or disruption, is identified by a responsible entity; and (4) Cyber Security Incident reports should continue to be sent to the Electricity Information Sharing and Analysis Center (E-ISAC), rather than the Commission, but the reports should also be sent to the Department of Homeland Security (DHS) Industrial Control Systems Cyber Emergency Response Team (ICS-CERT) now known as NCCIC[4]. Further, NERC must file an annual, public, and anonymized summary of the reports with the Commission.

The minimum attributes to be reported should include: (1) the functional impact, where possible to determine, that the Cyber Security Incident achieved or attempted to achieve; (2) the attack vector that was used to achieve or attempted to achieve the Cyber Security Incident; and (3) the level of intrusion that was achieved or attempted as a result of the Cyber Security Incident.

The Project 2018-02 SDT drafted Reliability Standard CIP-008-6 to require responsible entities to meet the directives set forth in the Commission's Order No. 848.

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[1] NERC's Compliance Guidance Policy

[2] 16 U.S.C. 824o(d)(5). The NERC Glossary of Terms Used in NERC Reliability Standards (June 12, 2018) (NERC Glossary) defines a Cyber Security Incident as "A malicious act or suspicious event that: Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter or, Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System."

[3] The NERC Glossary defines "ESP" as "[t]he logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol." The NERC Glossary defines "EACMS" as "Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Systems."

[4] The DHS ICS-CERT underwent a reorganization and rebranding effort and is now known as the National Cybersecurity and Communications Integration Center (NCCIC).

Definitions

CIP-008-6 has two related definitions, as well as language for "attempts to compromise" that is specific to CIP-008-6 within Requirement R1 Part 1.2.2. Cyber Security Incidents are not reportable until the Responsible Entity determines one rises to the level of a Reportable Cyber Security Incident or meets the Responsible Entity's established criteria pursuant to Requirement R1 Part 1.2.1 and 1.2.2. When these thresholds are reached reporting to both E-ISAC and NCCIC (Formerly DHS's ICS-CERT) is required. These definitions and requirement language are cited below for reference when reading the implementation guidance that follows.

Cyber Security Incident:
A malicious act or suspicious event that:

- Compromises, or was an attempt to compromise the (1) Electronic Security Perimeter, (2) Physical Security Perimeter, (3) Electronic Access Control or Monitoring Systems for High or Medium Impact BES Cyber Systems; or
- Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System.

Reportable Cyber Security Incident:
A Cyber Security Incident that has compromised or disrupted:

- A BES Cyber System that performs one or more reliability tasks of a functional entity;
- Electronic Security Perimeter(s); or
- Electronic Access Control or Monitoring Systems.

CIP-008-6 Table R1 – Cyber Security Incident Response Plan Specifications		
Part	**Applicable Systems**	**Requirements**
1.2	High Impact BES Cyber Systems and their associated: • EACMS Medium Impact BES Cyber Systems and their associated: • EACMS	One or more processes to: 1.2.1 Establish criteria to evaluate and define attempts to compromise; 1.2.2 Determine if an identified Cyber Security Incident is: • A Reportable Cyber Security Incident, or • Only an attempt to compromise one or more systems identified in the "Applicable Systems" column for this Part; and 1.2.3 Provide notification per Requirement R4.

The determination of reportability for compromises or disruptions (by definition), or for attempts to compromise (pursuant to the requirement language), becomes a function of applying criteria that builds upon the parent definition of Cyber Security Incident.

The below Venn diagram illustrates the relationships between the elements of each definition, and the Requirement R1 Part 1.2.2 requirement language. In this example, one potential option could be to leverage the EACMS function descriptors noted in FERC Order 848 Paragraph 54 as criteria. This could serve as an approach to assess operational impact and/or functionality of cybersecurity controls that cause a Cyber Security Incident to rise to either level of reportability:

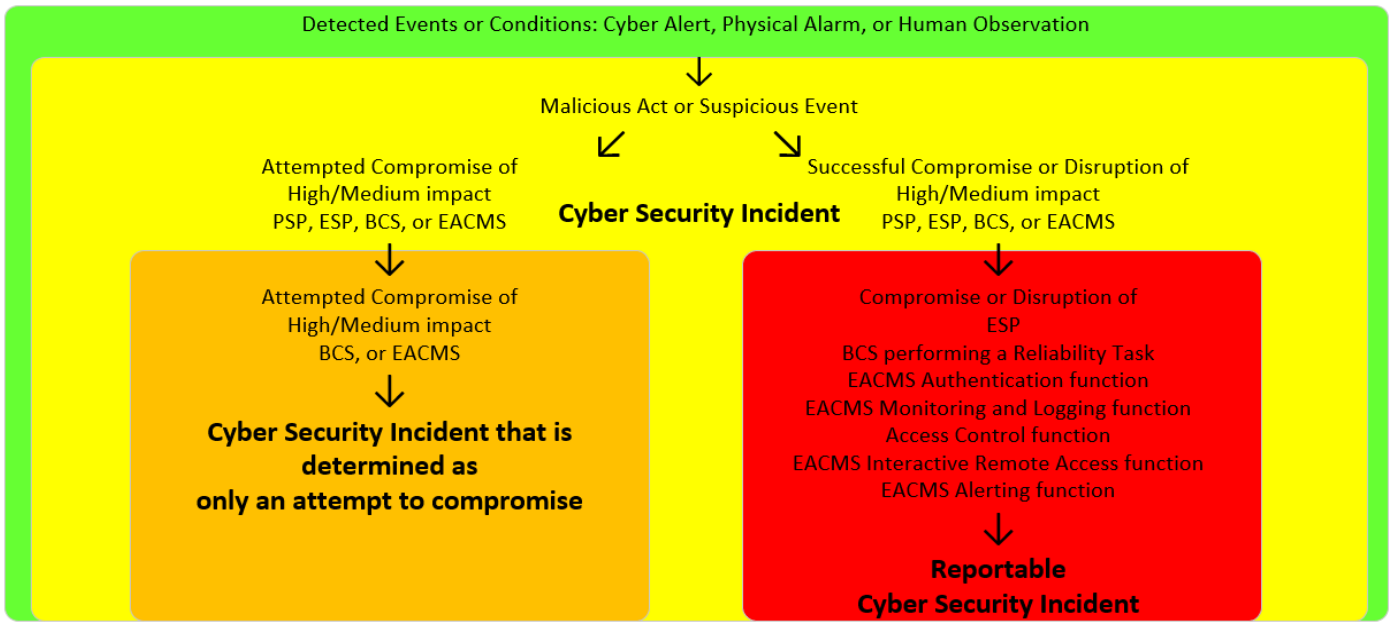


Figure 1 Relationship of Cyber Security Incidents

As shown in the above diagram, there is a progression from identification through assessment and response before a detected event or condition elevates to a reportable level.

First, the Registered Entity must determine the condition meets the criteria for a Cyber Security Incident.

Once the response and assessment has led to a Registered Entity's determination that events or conditions meet the definition of Cyber Security Incident, additional evaluation occurs to establish if established criteria or thresholds have been met for the Registered Entity to determine the Cyber Security Incident qualifies for one of the two reportable conditions:

1. Reportable Cyber Security Incident.
2. Only an attempt to compromise one or more systems identified in the "Applicable Systems" column for Requirement R4 Part 4.2 (pursuant to Responsible Entity processes and established attempt criteria documented in accordance with Requirement R1 Part 1.2)

Once the response and investigation has led to a Registered Entity's determination that the Cyber Security Incident has targeted or impacted the BCS performing reliability tasks and/or cybersecurity functions of the Applicable Systems, associated Cyber Assets, and/or perimeters, the notification and reporting timeframes and obligations begin. Note: Initial (or preliminary) notification is needed within the specified timeframe after this determination, even if required attributes (functional impact, level or intrusion,

attack vector) are not yet known.

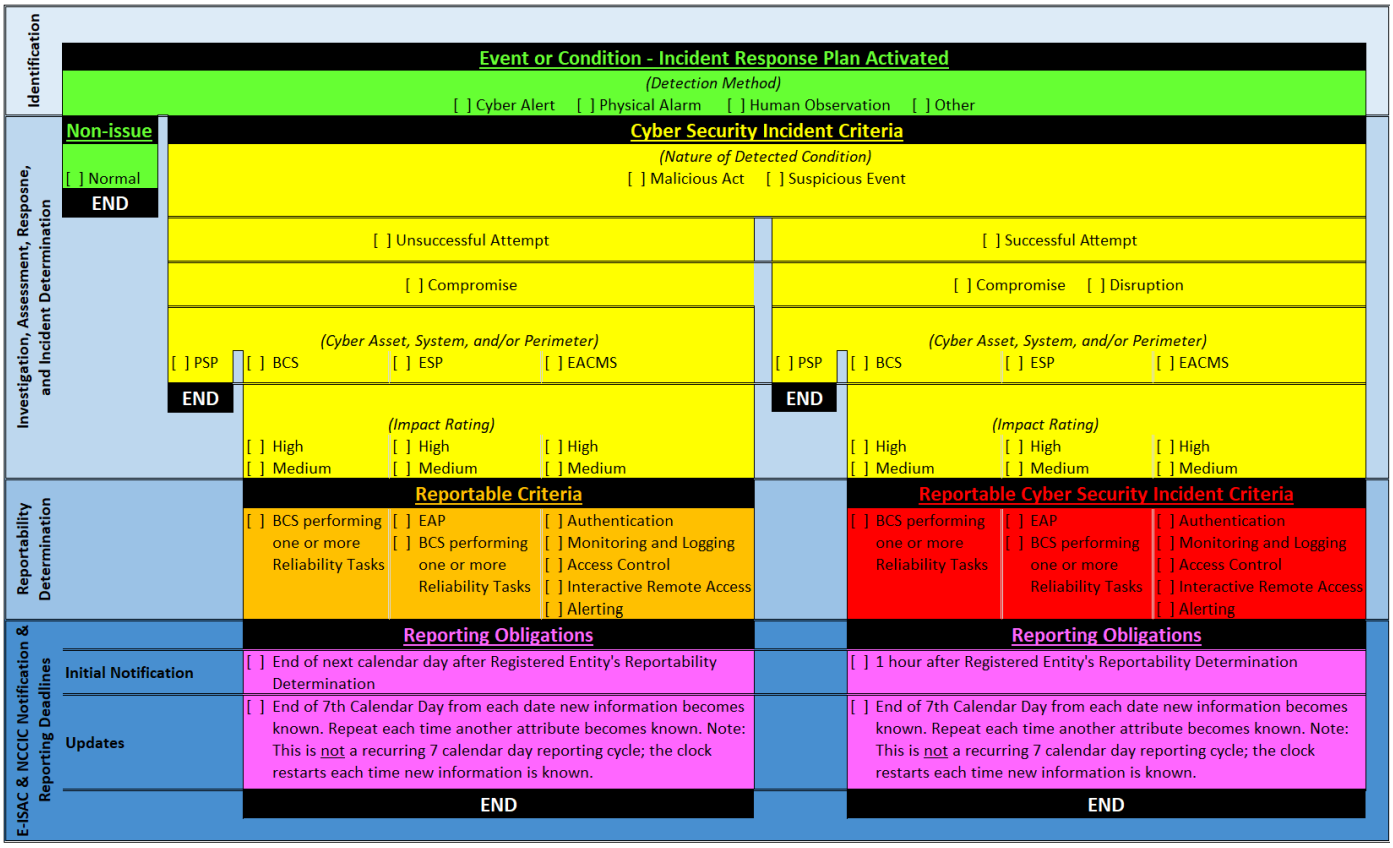
Once this initial notification is made, if all attribute were known, they should have been included in the initial notification and the reporting obligation ends.

If all attributes were not known by the time the initial notification had to be made, the update timeframes trigger from the time the next attribute(s) is learned/known.

A Registered Entity's reporting obligations are met once known information for the three required attributes is reported to E-ISAC and NCCIC, either during the initial notification or subsequently through one or more updates made commensurate with the reporting timeframes.

Determination and Classification of Cyber Security Incidents

Registered Entities may want to consider developing tools illustrating established process criteria that must be met, by definition, as well as the impacted/targeted operational task/cybersecurity functions considered to reach each incident classification and reporting threshold. The below decision tree is one potential approach Registered Entities could employ as a tool to assess events and make the Registered Entity determinations according to process(es) and established criteria documented pursuant to Requirement R1 Parts 1.1 and 1.2.



*Where 'Calendar Day' is used, the 'end' of the day = 11:59 PM local time of that day.
** Where 'Determination' is used, this refers to the Registered Entity's Determination.

Figure 2 Potential Approach Tool

A second potential approach could be a flow diagram illustrating an entity's criteria and determination process as depicted in the example below:

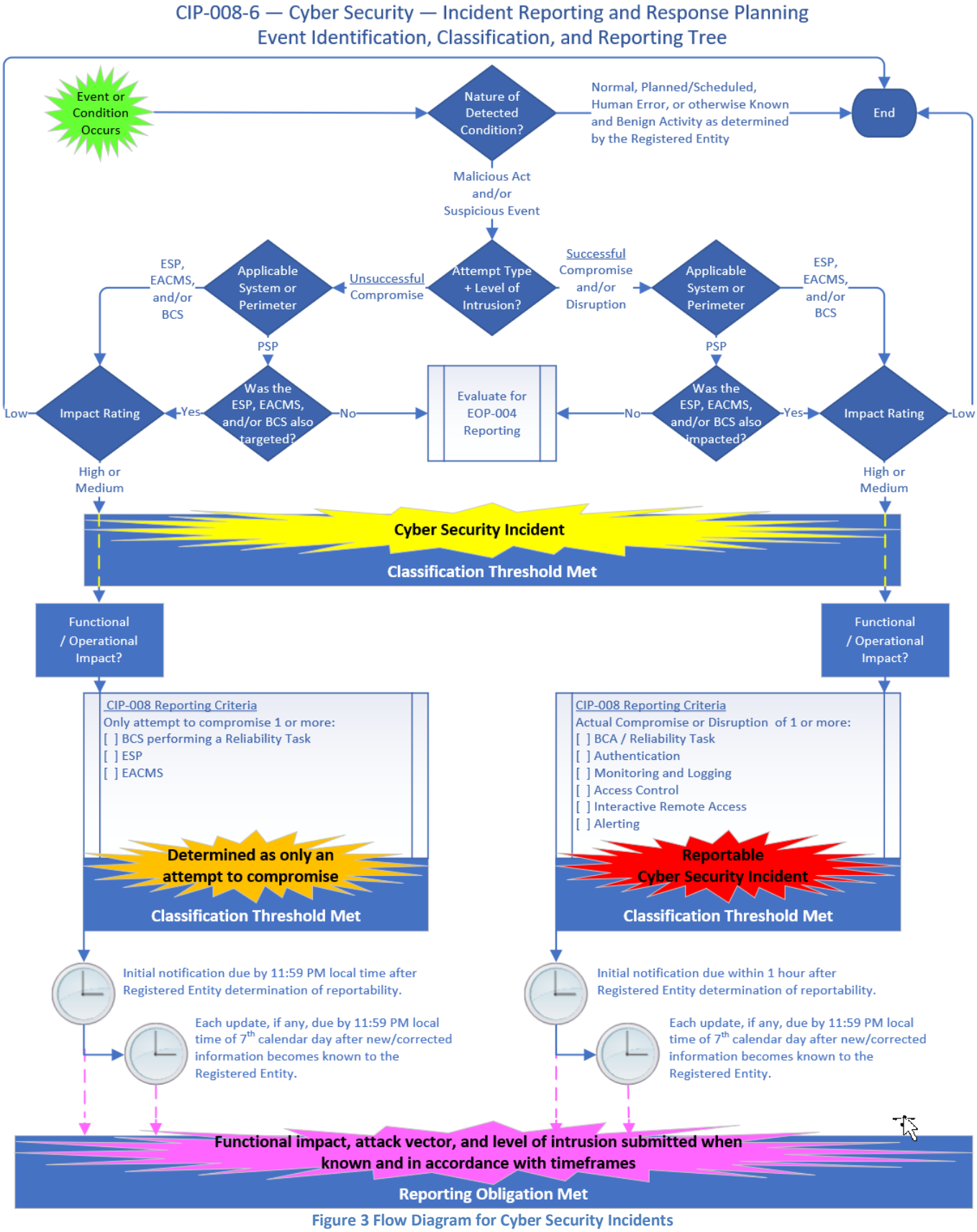


Figure 3 Flow Diagram for Cyber Security Incidents

Example of a Cyber Incident Classification Process

Entities may use a risk analysis-based method for the classification of cyber incidents and determination of Cyber Security Incidents, Reportable Cyber Security Incidents or, Cyber Security Incidents that attempted to compromise a system identified in the "Applicable Systems" column for the Part. The risk analysis-based approach allows entities the flexibility to customize the appropriate response actions for their situation without being administratively burdened by a one size fits all solution. Entities also have the flexibility to incorporate their existing incident management processes which may already define how they classify and determine cyber incidents.

A risk-based approach considers the number of cyber security related event occurrences, the probability that the events will have an impact on their facilities, and severity of the impact of the event. This allows the entity to decide when cyber events should be investigated as cyber incidents, the classification of cyber incidents and the determination of when a cyber incident should be reported; either as part of a voluntary action, as part of a Reportable Cyber Security Incident or a Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part.

Entities should also consider that appropriate reporting of cyber incidents helps other entities in similar situations. The reporting of the details of an incident serves to alert other entities so they may increase their vigilance and take timely preventive or mitigating actions. All entities stand to benefit from such shared information in the long run.

As an example, a typical infrastructure installation is depicted in Figure below.

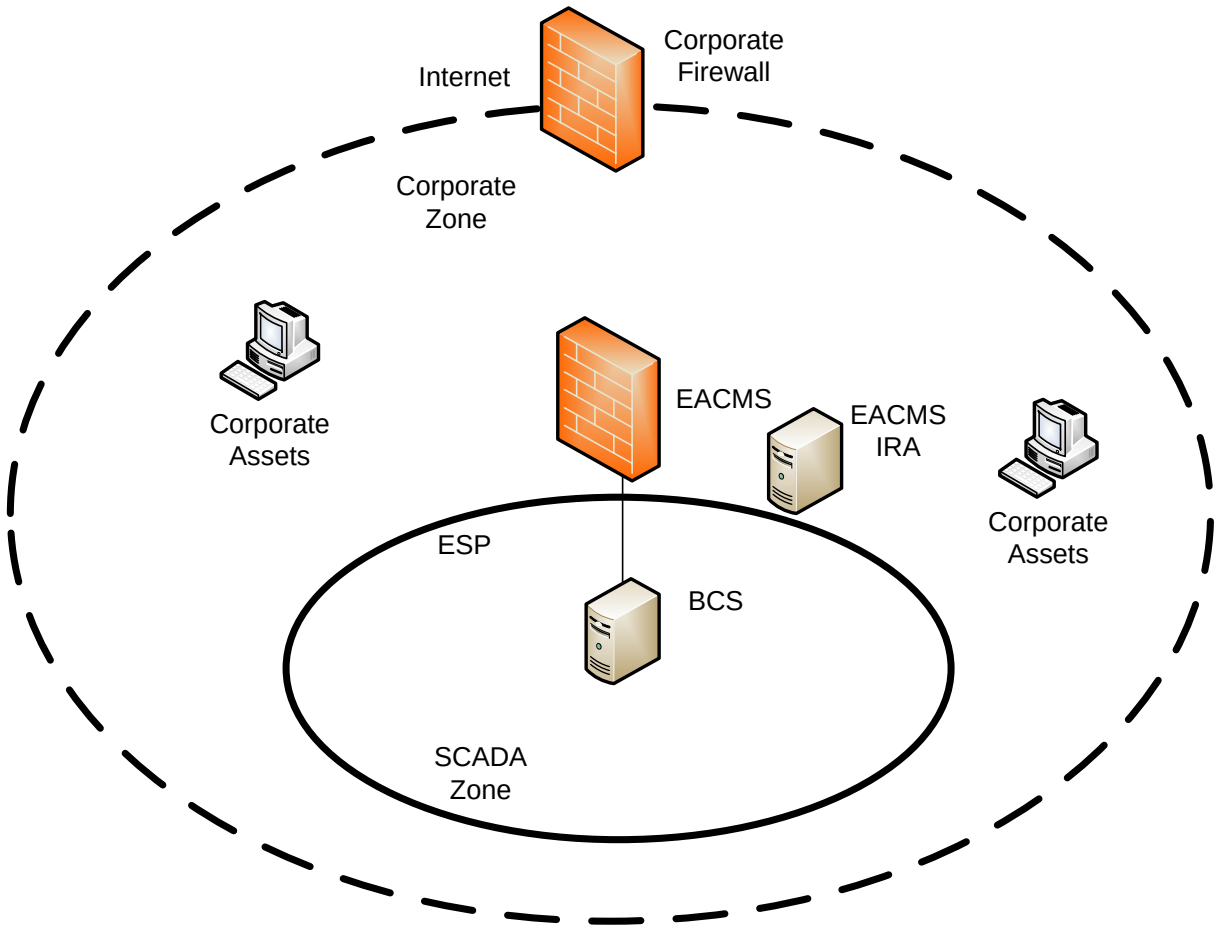


Figure 4 Typical Infrastructure

- A SCADA security zone consists of BES Cyber System (BCS), behind an Electronic Security Perimeter (ESP). The Electronic Access Point (EAP) is an interface of the SCADA firewall which is an Electronic Access Control or Monitoring System (EACMS).

- A Corporate security zone consists of regular corporate assets and other EACMS such as Intermediate Remote Access (IRA) systems. A corporate firewall protects the corporate assets against intrusions from the Internet. The SCADA security zone is nested inside the Corporate security zone.

Sample Classification Schema

A risk analysis could produce the incident categories below:

- Regular cyber events that represent a normal level of events where no further investigation is required such as random port-scans.
- Low risk incidents may be cyber events that become cyber incidents because they are beyond the normal level of events and require some type of investigation. Cyber incidents that are blocked at a firewall and found not to be malicious or suspicious could fall into this category.
- Medium risk incidents may be those cyber incidents that the entity has determined were malicious or suspicious and required mitigation activities.

  Note that while these cyber incidents were malicious or suspicious, they might not meet the definition of a Cyber Security Incident because the entity investigated and determined that the target was not a BCS, ESP, PSP or EACMS.

  For example, a corporate asset infected with well-known corporate malware and, as a result, is scanning the network to find other corporate assets. Although this activity is also being seen at the SCADA firewall (EACMS), the entity investigated and determined that this activity was not a Cyber Security Incident.
- High risk incidents may be those cyber incidents that the entity has determined were malicious or suspicious and did meet the definition of Cyber Security Incidents. For example, malicious malware on a corporate asset that repeatedly attempts to log into a SCADA IRA Intermediate System but is unsuccessful. This would be a Cyber Security Incident and should also fall into the entity's definition of a Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part with the target being an EACMS (SCADA IRA Intermediate System).
- Severe risk incidents may be those Cyber Security Incidents that involves successful compromise of an ESP or EACMS and hence meet the criteria for Reportable Cyber Security Incident. These may also escalate into Cyber Security Incidents that attempted to compromise a system identified in the "Applicable Systems" column for the Part such as the BCS.
- Emergency risk incidents may be those Cyber Security Incidents that compromised or disrupted a BCS that performs one or more reliability tasks of a functional entity. These incidents may represent an immediate threat to BES reliability and may require emergency actions such as external assistance.

These incident categories can be mapped into a standard incident classification and reporting schema like the NCCIC Cyber Incident Scoring System[5]. This is a common schema used by the United States Federal Cybersecurity Centers for describing the severity of cyber incidents and is available to industry to leverage.

Utilizing the NCCIC schema as a basis for identification and classification of Cyber Security Incidents could produce the schema below for application to CIP-008-6:

	General Definition	Observed Actions	Consequences
Level 5 Emergency Black	A Cyber Security Incident that has compromised or disrupted a BCS that performs one or more reliability tasks of a functional entity.	Effect	Incidents that result in imminent threat to public safety and BES reliability. REPORTABLE
Level 4 Severe	A Cyber Security Incident involving a compromise or disruption of an ESP or EACMS; OR Cyber Security Incidents that attempted to compromise a system identified in the "Applicable Systems" column for the Part such as a BCS.	Presence or Possible Effect	Cyber Security Incidents that have the potential to result in a threat to public safety and BES reliability if malicious or suspicious activity continues or escalates. Immediate mitigation is required. REPORTABLE
Level 3 High Orange	Cyber Security Incident that attempted to compromise an EACMS.	Presence	An attempt to compromise an EACMS does not result in a threat to public safety or BES reliability, but still requires mitigation. REPORTABLE
Level 2 Medium Yellow	A cyber incident that investigation found was malicious or suspicious but was not a Cyber Security Incident because it did not target an Applicable System or perimeter.	Engagement	A cyber incident that does not represent a threat to public safety or BES reliability, even though it is malicious or suspicious and required mitigation.
Level 1 Low Green	A cyber incident that investigation found was not malicious or suspicious.	Engagement	A cyber incident that does not represent a threat to public safety.
Level 0 Baseline	Inconsequential cyber events.	Preparation	Cyber events that require no investigation and are not cyber incidents. These do not represent a threat to public safety.

Figure 5 Example of Classification Schema

Reliability tasks may be those tasks that a Responsible Entity determines are associated with the BES Reliability Operating Services (BROS) listed in the NERC Functional Model within Attachment 1 of CIP-002.

[5] https://www.us-cert.gov/NCCIC-Cyber-Incident-Scoring-System

Examples of the use of the Sample Classification Schema

Some examples of the use of the classification schema are listed below. The event number corresponds to the events depicted in the subsequent figures

Type of Event (Event number)	Detection method	Mitigation	Cyber incident that requires investigation	Meets attributes of Cyber Security Incident	Meets attributes of Reportable Cyber Security Incident OR Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part	Comments
External firewall scan (N1)	External IPS log Review of F/W log	External IPS Corporate F/W rules	No	No	No	Determined by entity as regular background activity
Corporate Zone internal scan by non-malicious source (existing network monitoring Tool) (N2)	Corporate IPS Review of EACMS – IRA host F/W Log (CIP-007 R4)	Corporate IPS EACMS IRA Host F/W	No	No	No	Determined by entity as regular background activity – previously investigated and determined to be known source
Corporate Zone internal scan by unknown source (N3)	Corporate IPS Review of EACMS IRA host F/W Log	Corporate IPS IRA EACMS Host F/W	Yes	No	No	Investigation found new network monitoring tool. Added to regular background activity

Type of Event (Event number)	Detection method	Mitigation	Cyber incident that requires investigation	Meets attributes of Cyber Security Incident	Meets attributes of Reportable Cyber Security Incident OR Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part	Comments
Corporate Zone Internal scan by unknown source (N4)	Corporate IPS Corporate Antivirus Review of EACMS IRA host F/W Log Review of EACMS SCADA F/W Log	Corporate IPS IRA EACMS Host F/W Corporate Anti-virus SCADA F/W EACMS	Yes	No	No	Investigation by entity determined malware in Corporate zone that was targeting other corporate assets and not the applicable systems. (via the entity's criteria to evaluate and define attempts to compromise)
Corporate Zone Internal scan by unknown source followed by EACMS IRA login attempts (N5)	Corporate IPS Review of EACMS IRA host F/W Log Review of EACMS IRA failed Logins (CIP-007 R4)	Corporate IPS EACMS host F/W EACMS login 2 factor	Yes	Yes EACMS – IRA targeted	Yes Cyber Security Incidents that attempted to compromise a system identified in the "Applicable Systems" column for the Part	Investigation found malware in Corporate zone that was an attempt to compromise one or more applicable systems - IRA Intermediate System - EACMS (via the entity's criteria to evaluate and define attempts to compromise) **REPORTABLE**

Type of Event (Event number)	Detection method	Mitigation	Cyber incident that requires investigation	Meets attributes of Cyber Security Incident	Meets attributes of Reportable Cyber Security Incident OR Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part	Comments
Corporate Zone Internal scan by unknown source followed by successful EACMS IRA login and attempted BCS logins (N6)	SCADA IPS log Review of EACMS IRA host Logins (CIP-007 R4) Review of BCS failed Logins (CIP-007 R4)	SCADA IPS (CIP-005 R1.5) BCS user/ password login	Yes	Yes	Yes EACMS – IRA host compromised or disrupted Reportable Cyber Security Incident BCS host failed logins Cyber Security Incidents that attempted to compromise a system identified in the "Applicable Systems" column for the Part such as BCS	Investigation found malware that compromised or disrupted EACMS IRA. **REPORTABLE** Attempt to compromise a BCS (via the entity's criteria to evaluate and define attempts to compromise) **REPORTABLE**

Type of Event (Event number)	Detection method	Mitigation	Cyber incident that requires investigation	Meets attributes of Cyber Security Incident	Meets attributes of Reportable Cyber Security Incident OR Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part	Comments
BCS – SCADA system failure following Corporate Zone Internal scan by unknown source, successful EACMS IRA login and successful BCS login (N7)	SCADA system log Review of EACMS IRA host Logins (CIP-007 R4) Review of BCS Logins (CIP-007 R4)	None	Yes	Yes	Yes Comprise or disruption of a BCS performing one or more reliability tasks of a functional entity Reportable Cyber Security Incident	Investigation found malware that compromised a BCS performing one or reliability tasks of a functional entity **REPORTABLE**

Figure 6 Examples of the Use of the Classification Schema

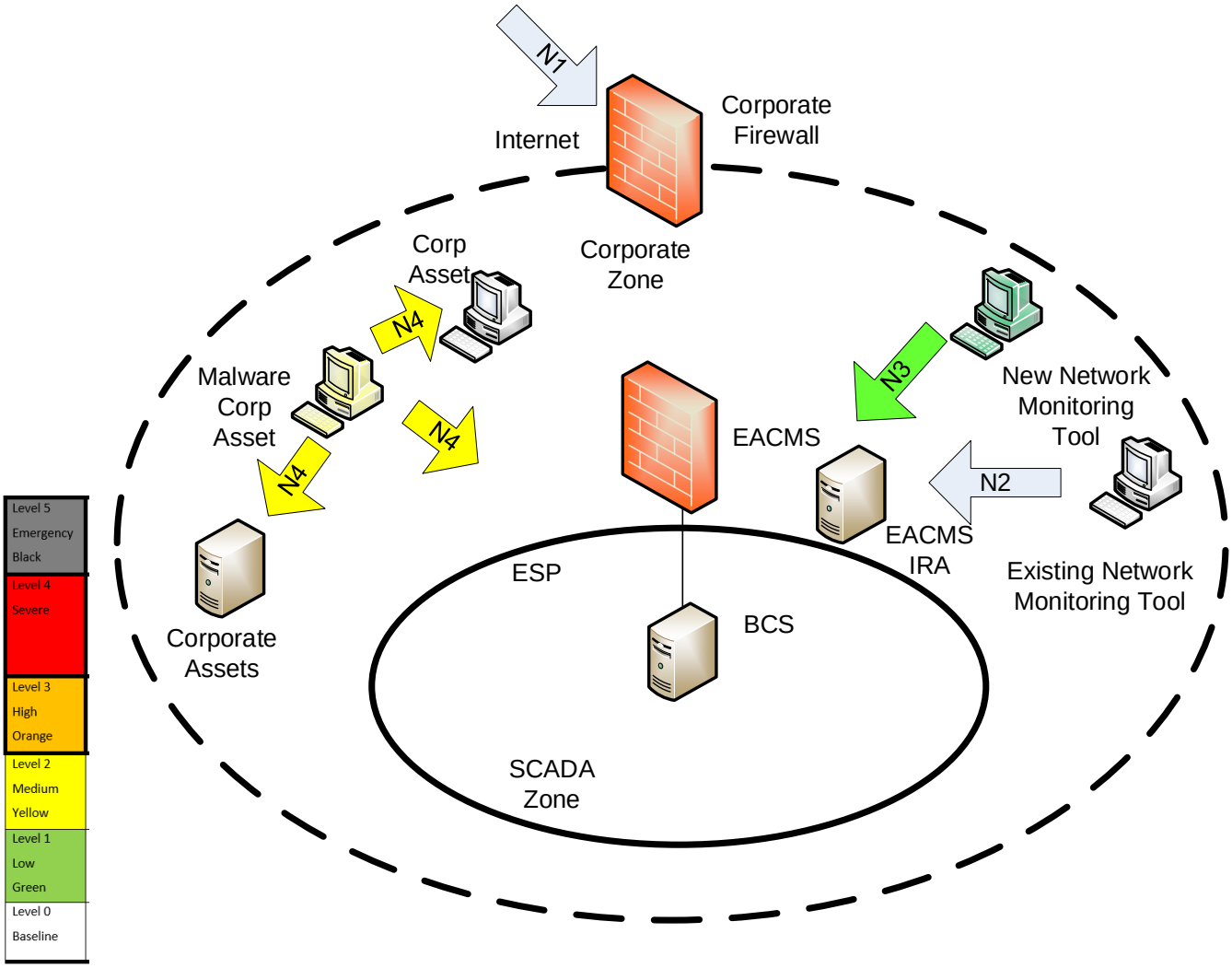


Figure 7 Examples of Non-Reportable Cyber Incidents

The figure above depicts examples of non-reportable cyber incidents using the sample classification schema and examples in Figure 6.

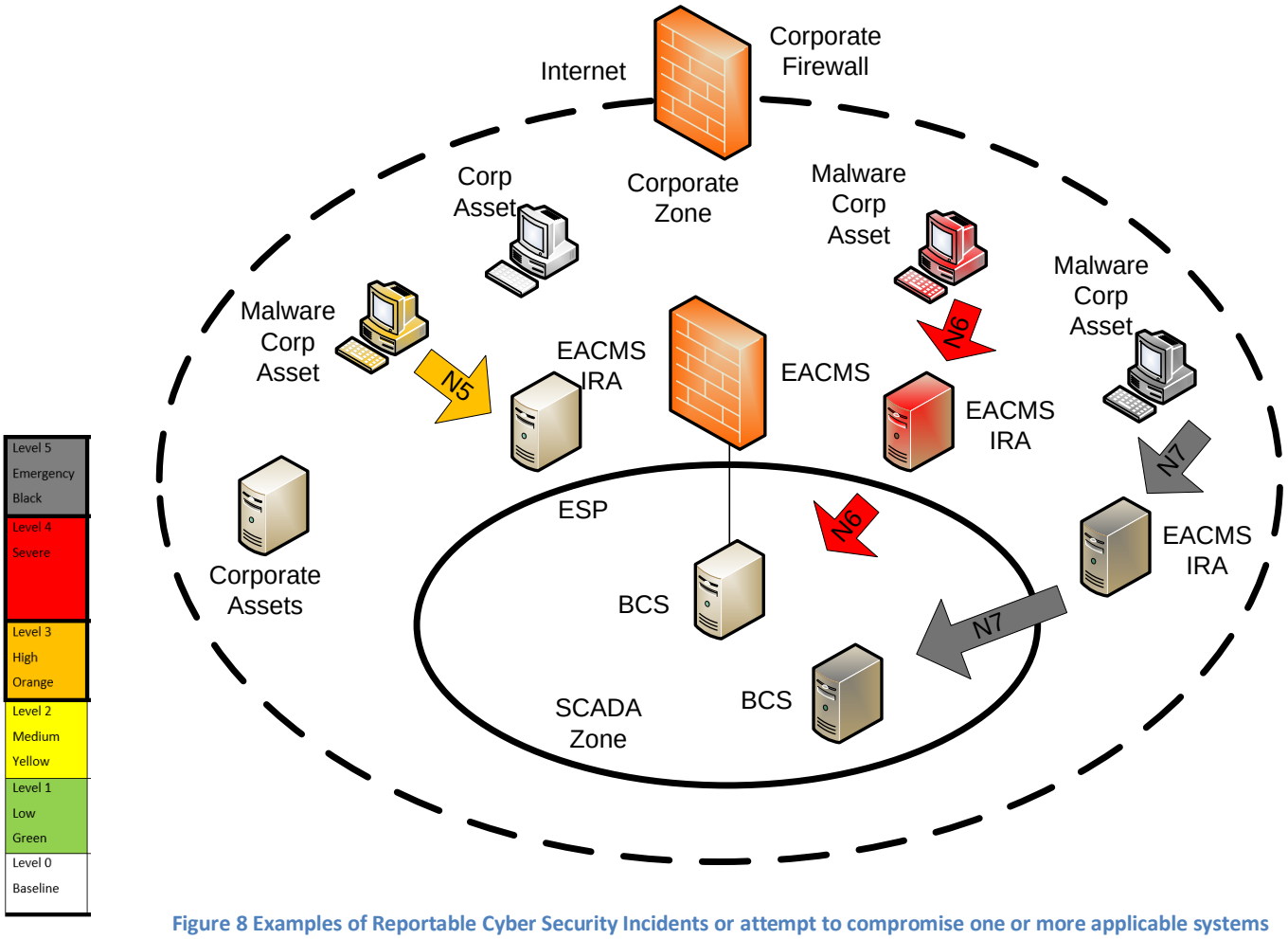


Figure 8 Examples of Reportable Cyber Security Incidents or attempt to compromise one or more applicable systems

The figure above depicts examples of Reportable Cyber Security Incidents or attempts to compromise one or more systems identified in the "Applicable Systems" column for the Part using the sample classification schema and examples in Figure 6.

Attempts to Compromise and Cyber Security Incidents

Registered Entities may want to evaluate and document what is normal within their environment to help scope and define network communications and activity that may constitute 'an attempt to compromise' in the context of CIP-008. This can help aid Subject Matter Experts (SMEs) in identifying deviations from normal, and could significantly assist a Registered Entity in timely and effective Incident determination, response, and vital information sharing. Since no two Registered Entities are alike, it stands to reason that interpretations and perspectives may vary.

Registered Entities are encouraged to explore options and tools designed to that take the guess work out of the process without being so overly prescriptive as to create undue administrative burden or remove needed discretion and professional judgment from the SMEs.

It is up to the Registered Entity to determine what constitutes and 'attempt to compromise', and this should be documented through the establishment of criteria that is incorporated into the Registered Entity's process. Once established, Registered Entities may want to consider incorporating a checklist to apply the defined set of criteria for SMEs to leverage as a part of the process to determine reportability.

As an example, a Registered Entity could define an "attempt to compromise" as an act with malicious intent to gain access or to cause harm to the normal operation of a Cyber Asset in the "Applicable Systems" column. Using this sample definition:

a. Actions that are **not** an attempt to compromise an applicable Cyber Asset/System electronically are:
   i. A Registered Entity's own equipment scanning a Cyber Asset for vulnerabilities or to verify its existence that is performed expected on demand or on an approved periodic schedule.
   ii. Broadcast traffic as part of normal network traffic. A firewall may block and log this traffic, but it does not have malicious intent.
   iii. Attempts to access a Cyber Asset by an authorized user that have been determined to fail due to human error.

b. Actions that **are** an attempt to compromise an applicable Cyber Asset/System electronically are:
   i. Scanning a Cyber Asset for vulnerabilities or to verify its existence that is not approved by the Registered Entity's management nor process(es). This could be from an entity's own equipment due to an upstream compromise or malware.
   ii. Attempts to access a Cyber Asset by a user that fails due to not being authorized and intending to gain access where no approval has been given.
   iii. Attempts to escalate privileges on a Cyber Asset by an authorized user that has been determined to fail due to not being authorize for that privilege level.

Registered Entities may also want to evaluate system architecture for ways to limit exposure for 'attempts to compromise'. Techniques like the implementation of security zones and/or network segmentation can minimize the level of traffic that can get to applicable Cyber Assets and help minimize the attack surface.

Registered Entities with implementations that involve an Electronic Access Control or Monitoring System (EACMS) containing both an Electronic Access Point (EAP) and a public internet facing interface are strongly encouraged to change this configuration in favor of architectures that offer layers of safeguards and a defense in depth approach.

Similarly, Registered Entities with implementations that involve an EACMS containing both an EAP and a corporate facing interface to their business networks may also want to consider options to re-architect to reduce cyber events from the corporate environment such as broadcast storms from causing extra administrative workload.

Examples of Cyber Security Incidents, attempts to compromise "Applicable Systems", and Reportable Cyber Security Incidents

The table below contains examples of various degrees of events or conditions at varied levels of determination:

Event	Normal or Benign	Malicious / Confirmed Suspicious
PSP breach	• Unauthorized user compromises the PSP to steal copper and the Registered Entity determines cybersecurity controls were not targeted and remain in place.	• Unauthorized user breaks into a Substation control house (**CIP-006-6 R1.5 activates BES Cyber Security Incident response plan within 15 minutes of detection.**)
		• Unauthorized user breaks into a Substation control house and inserts unauthorized Removable Media into an EACMS or BCS and the Registered Entity determines no interaction between the USB and the EACMS or BCS occurred. (**Cyber Security Incident pursuant to CIP-008-6 R1.1 determination**)
	• An equipment operator loses control of a backhoe and crashes into a control house, breaching the PSP and the Registered Entity determines it was accidental, cybersecurity controls were not targeted and remain in place.	• Registered Entity determines the unauthorized Removable Media contains malware (**determination of only an attempt to compromise one or more systems identified in the "Applicable Systems" column for CIP-008-6 R1.2**)
		• Registered Entity determines the malware has harvested the credentials of a BCS, gained unauthorized access and disrupted a reliability task. (**Reportable Cyber Security Incident pursuant to CIP-008-6 R1.2 determination**)
Port Scanning	• Registered Entity owned monitoring tool that runs scheduled periodic scans to detect deviations from baseline is scanning an EACMS or BCS at the expected time.	• Registered Entity owned monitoring tool that normally runs scheduled periodic scans to detect deviations from baseline is scanning an EACMS or BCS at an unexpected time and the Registered Entity has determined this as suspicious. (**Cyber Security Incident pursuant to CIP-008-6 R1.1 determination**)
	• A Registered Entity performs a port scan of an EACMS or BCS during a scheduled Cyber Vulnerability Assessment activity.	• Registered Entity owned monitoring tool that normally runs scheduled periodic scans to detect deviations from baseline is repeatedly scanning an EACMS or BCS and the Registered Entity determines it is targeting specific ports relevant to the BCS. (**determination of only an attempt to compromise one or more systems identified in the "Applicable Systems" column for CIP-008-6 R1.2**)
		• Registered Entity owned monitoring tool that normally runs scheduled periodic scans to detect deviations from baseline is repeatedly scanning an EACMS or BCS and the Registered Entity determines it gained unauthorized access to the EACMS or BCS. (**Reportable Cyber Security Incident pursuant to CIP-008-6 R1.2 determination**)

Event	Normal or Benign	Malicious / Confirmed Suspicious
Detected malware	• A corporate machine infected by a known Enterprise Windows-specific vulnerability is scanning all local hosts including a non-Windows-based EACMS or BCS and is determined by the Registered Entity to be an SMB exploit applicable to only Windows-based machines.	• An infected corporate machine is scanning all local hosts including an EACMS or BCS for well-known ports and determined to be a suspicious event by the Registered Entity. (**Cyber Security Incident pursuant to CIP-008-6 R1.1 determination**)
		• An infected corporate machine is scanning all local hosts including an EACMS or BCS for specific known ICS ports. (**determination of only an attempt to compromise one or more systems identified in the "Applicable Systems" column for CIP-008-6 R1.2**)
		• An infected corporate machine is scanning all local hosts including an EACMS or BCS for specific known ICS ports and has attempted to gain unauthorized access to the EACMS or BCS. (**determination of only an attempt to compromise one or more systems identified in the "Applicable Systems" column for CIP-008-6 R1.2**)
		• An infected corporate machine is scanning all local hosts including an EACMS or BCS for specific known ICS ports and exploited/compromised specified ICS ports that perform command and control functions of a BCS. (**Reportable Cyber Security Incident pursuant to CIP-008-6 R1.2 determination**)
Login activity	• Authorized user exceeded the Registered Entity defined threshold (CIP-007-6 R5.7) for unsuccessful login attempts against an EACMS or BCS and the Registered Entity confirmed the user incorrectly entered his/her password after performing annual password changes.	• Unknown individual attempts to login to a known default account on an EACMS or BCS with a publicly known default password, and the Registered Entity investigates that activity as a Cyber Security Incident deems suspicious. (**Cyber Security Incident pursuant to CIP-008-6 R1.1 determination**).
	• A system exceeds the Registered Entity defined threshold (CIP-007-6 R5.7) for unsuccessful login against an EACMS or BCS and locks out a system account and the Registered Entity confirmed the system account's password had changed but the accessing application/service had not yet been updated to use the new password.	• Unknown individual attempts to login to a known default account on an EACMS or BCS with a publicly known default password, and the Registered Entity's investigation determines that activity is being initiated from an external IP address and it continues aggressively with additional passwords and failed login attempts. (**determination of only an attempt to compromise one or more systems identified in the "Applicable Systems" column for CIP-008-6 R1.2**).
		• Unknown individual attempts to login to a known default account on an EACMS or BCS with a publicly known default password, and the Registered Entity's investigation determines that activity is being initiated from an external IP address and it continues aggressively with additional passwords and successfully gains unauthorized access to an EACMS or BCS. (**Reportable Cyber Security Incident pursuant to CIP-008-6 R1.2 determination**).

Figure 9 Examples of Cyber Security Incidents, attempts to compromise "Applicable Systems", and Reportable Cyber Security Incidents

Example of Sample Criteria to Evaluate and Define Attempts to Compromise

An entity may establish criteria to evaluate and define attempts to compromise based on their existing capabilities and facilities associated with the other CIP Standards.

The sample criteria listed below are examples and are not intended to be exhaustive.

CIP-005 R1.5:

Have one or more methods for detecting known or suspected malicious communications for both inbound and outbound communications.

Sample criteria:
Where investigation by entity was not able to determine that the source of the following was not suspicious and/or malicious:

- Detected known malicious or suspected malicious communications for both inbound and outbound communications.

CIP-005 R2.1:

Require multi-factor authentication for all Interactive Remote Access sessions.

Sample criteria:
Where investigation by entity was not able to determine that the source of the following was not suspicious and/or malicious:

- Repeated attempts to authenticate using multi-factor authentication

CIP-007 R4.1:

Log events at the BES Cyber System level (per BES Cyber System capability) or at the Cyber Asset level (per Cyber Asset capability) for identification of, and after-the-fact investigations of, Cyber Security Incidents that includes, as a minimum, each of the following types of events:

4.1.1. Detected successful login attempts;
4.1.2. Detected failed access attempts and failed login attempts;
4.1.3. Detected malicious code.

Sample criteria:
Where investigation by entity was not able to determine that the source of the following was not suspicious and/or malicious:

- Successful login attempts outside of normal business hours
- Successful login attempts from unexpected personnel such as those who are on vacation or medical leave
- Detected failed access attempts from unexpected network sources
- Detected failed login attempts to default accounts
- Detected failed login attempts from authorized personnel accounts exceeding X per day

- Detected failed login attempts from authorized personnel accounts where the account owner was not the source
- Detected malicious code on applicable systems

CIP-007 R5.7:

Where technically feasible, either:

- *Limit the number of unsuccessful authentication attempts; or*
- *Generate alerts after a threshold of unsuccessful authentication attempts.*

Sample criteria:
Where investigation by entity was not able to determine that the source of the following was not suspicious and/ or malicious:

- Account locked due to limit of unsuccessful authentication attempts exceeded more than X times per day
- Threshold of unsuccessful authentication attempts exceeds more than X every Y minutes

CIP-010 R2.1:

Monitor at least once every 35 calendar days for changes to the baseline configuration (as described in Requirement R1, Part 1.1). Document and investigate detected unauthorized changes.

Sample criteria:
Where investigation by entity was not able to determine that the source of the following was not suspicious and/ or malicious:

- Detected unauthorized changes to the baseline configuration

An entity may establish additional criteria to evaluate and define attempts to compromise based on their infrastructure configuration:

Sample criteria:
Where investigation by entity determines that the specific activity, while malicious or/and suspicious:

- Attempt to compromise was not intended to target the “Applicable Systems”

Requirement R1

R1. *Each Responsible Entity shall document one or more Cyber Security Incident response plan(s) that collectively include each of the applicable requirement parts in CIP-008-6 Table R1 – Cyber Security Incident Response Plan Specifications. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning].*

1.1. One or more processes to identify, classify, and respond to Cyber Security Incidents.

1.2. One or more processes:

1.2.1. Establish criteria to evaluate and define attempts to compromise;

- Determine if an identified Cyber Security Incident is A Reportable Cyber Security Incident or
- Only an attempt to compromise one or more systems identified in the "Applicable Systems" column for this Part; and

1.2.2. Provide notification per Requirement R4.

1.3. The roles and responsibilities of Cyber Security Incident response groups or individuals.

1.4. Incident handling procedures for Cyber Security Incidents.

General Considerations for R1

Preserved CIP-008-5 Version History from Guidelines and Technical Basis

An enterprise or single incident response plan for all BES Cyber Systems may be used to meet the Requirement.

The following guidelines are available to assist in addressing the required components of a Cyber Security Incident response plan:

- *Department of Homeland Security, Control Systems Security Program, Developing an Industrial Control Systems Cyber Security Incident Response Capability, 2009, online at* ***http://www.us-cert.gov/control_systems/practices/documents/final-RP_ics_cybersecurity_incident_response_100609.pdf***
- *National Institute of Standards and Technology, Computer Security Incident Handling Guide, Special Publication 800-61 revision 1, March 2008, online at* ***http://csrc.nist.gov/publications/nistpubs/800-61-rev1/SP800-61rev1.pdf***

For Part 1.2, a Reportable Cyber Security Incident is a Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity. It is helpful to distinguish Reportable Cyber Security Incidents as one resulting in a necessary response action.

A response action can fall into one of two categories: Necessary or elective. The distinguishing characteristic is whether or not action was taken in response to an event. Precautionary measures that are not in response to any persistent damage or effects may be designated as elective. All other response actions to avoid any persistent damage or adverse effects, which include the activation of redundant systems, should be designated as necessary.

Implementation Guidance for R1

Process to Identify, Classify, and Respond to Cyber Security Incidents (R1.1, R1.2)

The figure below is an example of a process that is used to identify, classify and respond to Cyber Security Incidents. This process uses the sample classification schema shown earlier that the entity uses to identify and classify Cyber Security Incidents as well as the sample criteria to evaluate and define attempts to compromise, if they are Reportable Cyber Security Incidents or Cyber Security Incidents that attempted to compromise a system identified in the "Applicable Systems" column for the Part.

This process is adapted from those related to the Information Technology Infrastructure Library (ITIL). ITIL is a set of detailed practices for IT service management (ITSM) that focuses on aligning IT services with the needs of business.

Note: There is recognition that the organizational structure and resource composition is unique to each entity and that roles and responsibilities may vary. The process diagram to follow is no intended to be prescriptive, and instead constitutes merely one potential approach where the assignments/functions in the cross functional swim lanes could be tailored to meet the unique needs of any entity.

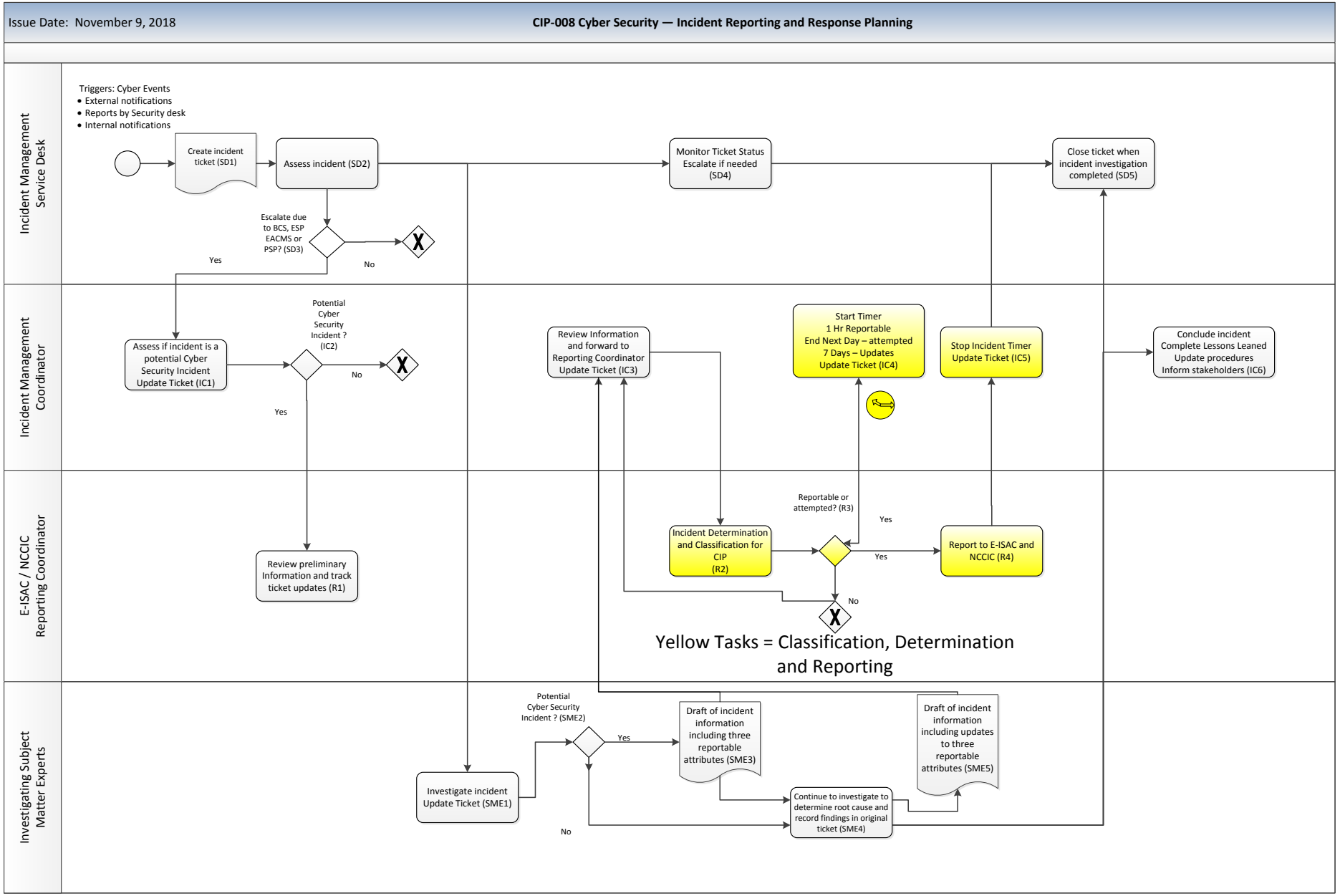


Figure 10 Sample Process to Identify, Classify and Respond to Cyber Security Incidents

Supporting Narrative Description of Sample Process to Identify, Classify, and Respond to Cyber Security Incidents (R1.1, R1.2)

1. The Incident Management Service Desk identifies that a cyber event that requires investigation has occurred.
2. Incident Management Service Desk creates an incident ticket to log the suspected cyber incident (SD1).
3. Incident Management Service Desk performs initial assessment of the suspected cyber incident and performs any initial triage or service restoration as needed (SD2).
4. If the suspected cyber incident involves BES Cyber Systems (BCS), Electronic Access Control or Monitoring Systems (EACMS), Electronic Security Perimeter (ESP) or Physical Security Perimeters (PSP), the Incident Management Service Desk will escalate the incident to an Incident Management Coordinator whom will act as the coordinator until the incident is closed (SD3)
5. The Incident Management Coordinator performs a secondary initial assessment to determine if the incident has the potential to be a Cyber Security Incident, a Reportable Cyber Security Incident, or a Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part.

   They update the incident ticket, assigning the appropriate Investigating Subject Matter Experts (IC1).
6. If the Incident Management Coordinator determines that the incident has the potential to be reportable, the E-ISAC/ NCCIC Reporting Coordinator is alerted and copied on the information contained in the incident ticket. The E-ISAC/ NCCIC Reporting Coordinator continues to monitor the updates to the incident ticket (IC2)
7. The Incident Management Service Desk ensures the assigned Investigating SMEs are notified, and the incident ticket information is updated (SD2, SD4)
8. The assigned SMEs investigate the incident ticket updating with the Incident Management Coordinator as appropriate (SME1). The Incident Management Coordinator will monitor the progress of the investigation and assign additional SMEs or escalate as needed.
9. If initial investigation by SMEs finds that the incident may be a Cyber Security Incident and has the potential to be reportable (SME2), the SMEs will inform the Incident Management Coordinator and forward the known information including the required three attributes (SME3). Attributes which are unknown at the current time will be reported as "unknown".
10. The SMEs will continue their investigation to determine the root cause of the incident, performing triage or service restoration as needed, continue to investigate the three required attributes and update incident ticket information (SME4).
11. If the incident is found to be potentially reportable, the Incident Management Coordinator reviews the information, adds any details collected by other investigating SMEs and resolves any missing information as needed. The information is forwarded to the E-ISAC/ NCCIC Reporting Coordinator (IC3)
12. The E-ISAC/ NCCIC Reporting Coordinator reviews the information received, performs classification of the incident (R2). They determine if the incident is a Cyber Security Incident and determine if it is either a Reportable Cyber Security Incident or Cyber Security Incident that attempted to compromise

a system identified in the "Applicable Systems" column for the Part. The information to be reported is finalized (R3).

13. Upon determination that the incident is reportable, E-ISAC/ NCCIC Reporting Coordinator informs the Incident Management Coordinator to begin a clock timer set to the appropriate time frame (IC4) and performs the required notification including the three required attributes. The incident ticket is updated with the incident classification and determination time for compliance evidence purposes:
    - Within 1 hour for initial notification of Reportable Cyber Security Incident,
    - By end of the next day for a Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part,
    - Within 7 calendar days of determination of new or changed attribute information required in Part 4.1

14. The E-ISAC/ NCCIC Reporting Coordinator informs the Incident Management Coordinator when notification is completed and time that the notifications occurred at. The Incident Management Coordinator will stop the appropriate timer and updates the incident ticket with the appropriate information for compliance evidence purposes (IC5)
15. If Incident Management Coordinator that has not received confirmation of notification, they may escalate, as needed, prior to expiry of the applicable timer. Upon expiry of the timer, the Incident Management Coordinator must inform the CIP Senior Manager (IC4)
16. During the continued investigation of the incident (SME4), the SMEs may find that an update of any of the three required attributes is potentially required. The SMEs will inform the Incident Management Coordinator and forward a draft of the updated information (SME5)
17. The Incident Management Coordinator reviews the draft update information including adding other details, and then informs E-ISAC/ NCCIC Reporting Coordinator, forwarding the potential update information (IC3)
18. The E-ISAC/ NCCIC Reporting Coordinator reviews the potential updated information and determines if the update to any of the three required attributes is reportable (R3).
19. Upon determination that the update is reportable, E-ISAC/ NCCIC Reporting Coordinator informs the Incident Management Coordinator to begin a timer set to the appropriate time frame (i.e. 7 calendar days). The incident ticket is updated with the determination time for compliance evidence purposes (IC4)
20. The E-ISAC/ NCCIC Reporting Coordinator updates both E-ISAC and NCCIC with the information associated with any of the three required attributes (R4)
21. The E-ISAC/ NCCIC Reporting Coordinator informs the Incident Management Coordinator that the update to E-ISAC and NCCIC is completed and times that the updates occurred at. The Incident Management Coordinator will stop the appropriate timer and update the incident ticket with the appropriate information for compliance purposes (IC5)

22. If the Incident Management Coordinator that has not received confirmation of the update being completed, prior to the expiration of the timer, they may escalate as needed. Upon expiry of the timer, the Incident Management Coordinator must inform the CIP Senior Manager (IC4)
23. Upon closure of the incident, the Incident Management Coordinator will ensure that the last reportable update to the three required attributes accurately reflects the closure information. If a further update of the three required attributes is required, the Incident Management Coordinator will inform the appropriate Subject Matter Expert to initiate an update (SME5).
24. The Incident Management Coordinator informs the Incident Management Service Desk that the incident ticket may be closed (SD5).
25. The Incident Management Coordinator will initiate a "Lessons Leaned" session and update to the Cyber Incident Reporting and Response Plan and any other documentation, procedures, etc. within 90 days (IC6). They will inform all stakeholders of any updates to the Cyber Incident Reporting and Response Plan and any other applicable documentation

Roles and Responsibilities (R1.3)

In the example process, the defined Roles and Responsibilities are as follows, but can be tailored by any entity to align with their unique organization:

- Incident Management Service Desk is responsible for initial activities, incident ticketing and incident logging:
    - Initial identification, categorization and prioritization,
    - Initial diagnosis and triage/service restoration,
    - Initial assignment of incident tickets to Investigating Subject Matter Experts (SMEs)
    - Initial escalation to an Incident Management Coordinator upon assessment (if needed)
    - Monitoring incident ticket status and initiating further escalation (if needed)
    - Incident ticket resolution and closure
    - General incident status communication with the user community

- Incident Management Coordinator is responsible for the over-all coordination of activities related to an assigned incident:
    - Detailed assignment of tasks to Investigating SMEs
    - Ensure that all assigned activities are being performed in a timely manner
    - Ensuring regulatory reporting time limits are met and initiating escalation if needed
    - Communicating incident status with major affected stakeholders
    - Coordinating with the Incident Management Service Desk to update incident tickets with status and the logging of required details and assisting them to perform general incident status communications with the user community

- Coordinating with the E-ISAC/NCCIC Reporting Coordinator for cyber incidents with the potential of being Cyber Security Incidents, Reportable Cyber Security Incidents or Cyber Security Incidents that attempted to compromise a system identified in the "Applicable Systems" column for the Part. Assisting the E-ISAC/NCCIC Reporting Coordinator with information to aid in the classification of the cyber incident.
- Escalation as needed according to the priority and severity of the issue
- Coordination of service restoration and incident closure
- Coordination of incident review following closure of incidents, identification of potential problems and documenting the "Lessons Learned"
- Initiating update of processes or procedures as needed and communicating the updates to stakeholders

- E-ISAC/ NCCIC Reporting Coordinator is responsible for the coordination of regulatory reporting activities such as those related to E-ISAC and NCCIC:
  - Review of completeness incident information for classification and reporting purposes
  - Incident classification for reporting purposes
  - Determination if this incident is a Cyber Security Incident, Reportable Cyber Security Incident or a Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part
  - Completeness of the required three attributes to be reported
  - Notification to E-ISAC and NCCIC and submission of the three required attributes
  - Coordinating with Incident Management Coordinator to ensure timing is in accordance with regulatory requirements and that incident logging is complete for compliance evidence purposes

- Investigating Subject Matter Experts are responsible for detailed technical tasks related to the investigation of the incident and performing the needed recovery actions:
  - Perform investigation tasks related to the incident as assigned by the Incident Management Coordinator to determine the root cause of the incident
  - Perform service restoration tasks related to the incident as assigned
  - Update incident ticket and ensure all required details are logged
  - Obtaining information on the three required attributes for both initial notification and updates
  - After incident closure, participate in "Lessons Learned" sessions and update procedures as needed

Incident handling procedures for Cyber Security Incidents (R1.4)

Each of the defined roles in the example process may have specific procedures covering various aspects of their tasks being accomplished within the process. The sample process documents "what" the overall required steps are whereas the procedures document "how" each step is carried out:

- Incident Management Service Desk Procedures:
    - Procedures of when to classify cyber events as possible cyber incidents
    - Procedures to determine if BCS, PSP, ESP or EACMS are involved and decision criteria of when to escalate to an Incident Management Coordinator.
    - Procedures for initial diagnosis, triage and service restoration
    - Procedures for incident ticketing, assignment, escalation and closure

- Incident Management Coordinator Procedures:
    - Procedures for finding if cyber events or incidents could be possible Cyber Security Incidents, Reportable Cyber Security Incidents or Cyber Security Incidents that attempted to compromise a system identified in the "Applicable Systems" column for the Part. These potential incidents require notification to the E-ISAC/ NCCIC Coordinator
    - Procedures for the assignment and tracking of tasks to Investigating SMEs
    - Procedures associated with regulatory reporting time limits
    - Procedures for incident review, documentation of lessons learned, tracking of completion of documentation update status
- E-ISAC/ NCCIC Reporting Coordinator Procedures:
    - Procedures on how to use the Entity's own classification and reporting schema to classify cyber incidents and determine Cyber Security Incidents, Reportable Cyber Security Incidents or Cyber Security Incidents that attempted to compromise a system identified in the "Applicable Systems" column for the Part
    - Procedures on the review of information to be used for reporting the three required attributes to be included for E-ISAC or NCCIC notification including the handling of any BES Cyber System Information
    - Procedures for the notification of updates to E-ISAC and NCCIC including the submission of the three required attributes
- Investigating Subject Matter Experts Procedures:
    - Procedures for the classification of cyber incidents to possible Cyber Security Incidents, possible Reportable Cyber Security Incidents or possible Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part and the required information needed to be obtained.
    - Procedures for troubleshooting tasks to determine root cause of an incident

- Procedures for service restoration tasks after an incident
- Procedures for triggering the forensic preservation of the incident
- Procedures on when updates are necessary to information on the required attributes associated with a Reportable Cyber Security Incident or a Cyber Security Incident that attempted to compromise a system identified in the “Applicable Systems” column for the Part

Requirement R2

R2. *Each Responsible Entity shall implement each of its documented Cyber Security Incident response plans to collectively include each of the applicable requirement parts in CIP-008-6 Table R2 – Cyber Security Incident Response Plan Implementation and Testing. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning and Real-Time Operations]*

2.1. Test each Cyber Security Incident response plan(s) at least once every 15 calendar months:

- By responding to an actual Reportable Cyber Security Incident;
- With a paper drill or tabletop exercise of a Reportable Cyber Security Incident; or
- With an operational exercise of a Reportable Cyber Security Incident.

2.2. Use the Cyber Security Incident response plan(s) under Requirement R1 when responding to a Reportable Cyber Security Incident, Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part, or performing an exercise of a Reportable Cyber Security Incident. Document deviations from the plan(s) taken during the response to the incident or exercise.

2.3. Retain records related to Reportable Cyber Security Incidents and Cyber Security Incidents that attempted to compromise a system identified in the "Applicable Systems" column for this Part.

General Considerations for R2

Preserved CIP-008-5 Version History from Guidelines and Technical Basis

If a plan is written at a high enough level, then every action during the response should not be subject to scrutiny. The plan will likely allow for the appropriate variance in tactical decisions made by incident responders. Deviations from the plan can be documented during the incident response or afterward as part of the review.

For more specific types of exercises, refer to the FEMA Homeland Security Exercise and Evaluation Program (HSEEP). It lists the following four types of discussion-based exercises: seminar, workshop, tabletop, and games. In particular, it defines that, "A tabletop exercise involves key personnel discussing simulated scenarios in an informal setting. Table top exercises (TTX) can be used to assess plans, policies, and procedures."

The HSEEP lists the following three types of operations-based exercises: Drill, functional exercise, and full-scale exercise. It defines that, "[A] full-scale exercise is a multi-agency, multi-jurisdictional, multi-discipline exercise involving functional (e.g., joint field office, Emergency operation centers, etc.) and 'boots on the ground' response (e.g., firefighters decontaminating mock victims)."

In addition to the requirements to implement the response plan, Part 2.3 specifies entities must retain relevant records for Reportable Cyber Security Incidents. There are several examples of specific types of

evidence listed in the measure. Entities should refer to their handling procedures to determine the types of evidence to retain and how to transport and store the evidence. For further information in retaining incident records, refer to the NIST Guide to Integrating Forensic Techniques into Incident Response (SP800-86). The NIST guideline includes a section (Section 3.1.2) on acquiring data when performing forensics.

Implementation Guidance for R2

Acceptable Testing Methods

The SDT made no changes to the testing requirements located in Requirement Parts 2 and 3. The applicable system expansion to include EACMS was the only change. The SDT purposefully did not expand the acceptable testing methods to include an actual response to a Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part. This was based on incident risk level and benefits of exercising the full response plan(s).

Annual testing of the incident response plan(s) are important because they may reveal weaknesses, vulnerabilities, and opportunity for improvement. The current test options include: a paper drill (coordinated tabletop exercise), an operational exercise (a full-scale, multiple entity exercise), and actual response to a Reportable Cyber Security Incident.

All of these options, especially the latter, involve a complete, step-by-step run-through of the plan components. Many problems that would occur in a real incident also will be present in the test exercise or drill[6]. In fact, it is recommended that drills and exercises go to the extreme and simulate worst-case scenarios.

Conversely, a Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part, may only exercise several components and would likely not result in the same level of response action. Cyber Security Incidents that attempted to compromise an applicable system, by their very nature, have less risk than an actual compromise. A Responsible Entity's actual response to unauthorized access attempts and suspicious activities does not rise to the same level of required response that actual disruption of a BCS performing one or more reliability tasks would. For these reasons, the SDT did not change the acceptable testing methods of a response plan(s), and using records associated to attempts to compromise are not sufficient evidence to demonstrate compliance with the 15-month testing requirements.

The sample process in Requirement R1.1 shows how an actual Reportable Cyber Security Incident is documented using the entity's incident management system including how each role defined in Requirement R1.3 updates the incident ticket. The incident ticket is a permanent record of the incident including any actions undertaken. The Incident Management Coordinator is responsible for documenting deviations from the Cyber Incident response plan and initiating any corrections required in the process or documentation for meeting the Requirement. In addition, to assure sufficient evidence, records should be dated and should include documentation that sufficiently describes the actual or simulated scenario(s), response actions, event identifications and classifications, the application of Cyber Security Incident and reportability criteria, reportability determinations, and reporting submissions and timeframes.

[6] 2009, Department of Homeland Security, Developing an Industrial Control Systems Cybersecurity Incident Response Capability, page 13.

Requirement R3

R3. *Each Responsible Entity shall maintain each of its Cyber Security Incident response plans according to each of the applicable requirement parts in CIP-008-6 Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication. [Violation Risk Factor: Lower] [Time Horizon: Operations Assessment].*

3.1. No later than 90 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident response:

3.1.1. Document any lessons learned or document the absence of any lessons learned;

3.1.2. Update the Cyber Security Incident response plan based on any documented lessons learned associated with the plan; and

3.1.3. Notify each person or group with a defined role in the Cyber Security Incident response plan of the updates to the Cyber Security Incident response plan based on any documented lessons learned.

3.2. No later than 60 calendar days after a change to the roles or responsibilities, Cyber Security Incident response groups or individuals, or technology that the Responsible Entity determines would impact the ability to execute the plan:

3.2.1. Update the Cyber Security Incident response plan(s); and

3.2.2. Notify each person or group with a defined role in the Cyber Security Incident response plan of the updates.

General Considerations for R3

Preserved CIP-008-5 Version History from Guidelines and Technical Basis

The process of conducting lessons learned can involve the response team discussing the incident to determine gaps or areas of improvement within the plan. Any documented deviations from the plan from Part 2.2 can serve as input to the lessons learned. It is possible to have a Reportable Cyber Security Incident without any documented lessons learned. In such cases, the entity must retain documentation of the absence of any lessons learned associated with the Reportable Cyber Security Incident.

Entities should consider meeting with all of the individuals involved in the incident and documenting the lessons learned as soon after the incident as possible. This allows more time for making effective updates to the plan, obtaining any necessary approvals, and distributing those updates to the incident response team.

This may include changes to the names or contact information listed in the plan. Technology changes affecting the plan may include referenced information sources, communication systems or ticketing systems.

Implementation Guidance for R3

The sample process in Requirement R1.1 shows how an actual Reportable Cyber Security Incident results in an update to Cyber Security Incident response plan, incorporating the "lessons learned". The role of Incident Management Coordinator includes the responsibility for meeting Requirement R3. Registered Entities should assure updated plans are dated in demonstration of the timelines mandated by Requirement R3. It may help to append these records to the dated Lessons Learned from an actual response or an exercise to test the plan to further demonstrate plan update timelines were met and relevant areas of the plan were updated to align with the outcomes and conclusions in the Lessons Learned.

Requirement R4

R4. Each Responsible Entity shall notify the Electricity Information Sharing and Analysis Center (E-ISAC) and, if subject to the jurisdiction of the United States, the United States National Cybersecurity and Communications Integration Center (NCCIC), or their successors, of a Reportable Cyber Security Incident and a Cyber Security Incident that was an attempt to compromise a system identified in the "Applicable Systems" column, unless prohibited by law, in accordance with each of the applicable requirement parts in *CIP-008-6 Table R4 – Notifications and Reporting for Cyber Security Incidents*. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment].*

4.1. Initial notifications and updates shall include the following attributes, at a minimum, to the extent known:

4.1.1 The functional impact;

4.1.2 The attack vector used; and

4.1.3 The level of intrusion that was achieved or attempted.

4.2. After the Responsible Entity's determination made pursuant to documented process(es) in Requirement R1, Part 1.2, provide initial notification within the following timelines:

- One hour after the determination of a Reportable Cyber Security Incident.
- By the end of the next calendar day after determination that a Cyber Security Incident was an attempt to compromise a system identified in the "Applicable Systems" column for this Part.

4.3. Provide updates within 7 calendar days of determination of new or changed attribute information required in Part 4.1

General Considerations for R4

Registered Entities may want to consider designing tools or mechanisms to assure incident responders have the information needed to efficiently and timely report events or conditions that rise to the level of reportability. A potential approach is to include the E-ISAC/NCCIC phone numbers in response plans, calling trees, or even within corporate directories for ease of retrieval. Another potential approach is to develop a distribution list that includes both entities so one notification can easily be sent at the same time. Certainly, Registered Entities should consider implementing secure methods for transit if using email. Another approach could be to incorporate website URLs into processes to have them at hand. Finally, for Registered Entities that prefer to leverage secure portals for E-ISAC or NCCIC, advance planning by having individual user portal accounts requested, authorized, configured, and tested is encouraged ad can be a time saver in emergency situations.

Implementation Guidance for R4

The sample process in Requirement R1.1 shows how initial notification and updates of the required attributes is performed within the specified time lines (yellow colored tasks).

For attributes that are not known, these should be reported as "unknown"

NCCIC Reporting

NCCIC reporting guidelines for reporting events related to Industrial Control Systems can be found here:

https://ics-cert.us-cert.gov/Report-Incident

https://www.us-cert.gov/incident-notification-guidelines

NCCIC prefers the reporting of 10 attributes, although they will accept any information that is shared. A potential mapping between the NCCIC preferred attributes and the attributes required to comply with CIP-008-6 standard could be represented are as follows:

CIP-008-6 Reporting	NCCIC Reporting	Comment
Functional Impact	Identify the current level of impact on agency functions or services (Functional Impact).	
Functional Impact	Identify the type of information lost, compromised, or corrupted (Information Impact).	
Functional Impact	Identify when the activity was first detected.	
Level of Intrusion	Estimate the scope of time and resources needed to recover from the incident (Recoverability).	
Level of Intrusion	Provide any indicators of compromise, including signatures or detection measures developed in relationship to the incident	
Level of Intrusion	Identify the number of systems, records, and users impacted.	
Level of Intrusion	Identify the network location of the observed activity.	
Level of Intrusion	Provide any mitigation activities undertaken in response to the incident.	
Attack Vector	Identify the attack vector(s) that led to the incident.	
Name and Phone	Identify point of contact information for additional follow-up.	

Figure 11 NCCIC Reporting Attributes

Example of a Reporting Form

Entities may wish to create an internal standard form to be used to report Reportable Cyber Security Incidents and Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part. The advantages of using a standard internal form are:

- A standard internal format for the communications of cyber incident information between the various internal roles with respect to obligations of CIP-008-6, Requirement R4
- A standard written record of the notification of the minimum 3 attributes having been reported to E-ISAC and NCCIC in accordance with CIP-008-6, Requirement R4 which can be easily stored, sorted and retrieved for compliance purposes

An example of an internal standard form is shown. The instructions on how to complete this form are included after it.

CIP-008-6 Requirement R4

Cyber Security Incident Reporting Form

This form may be used to report Reportable Cyber Security Incidents and Cyber Security Incidents that were an attempt to compromise a system listed in the "Applicable Systems" column for the Part.

Contact Information

Name: Click or tap here to enter text.

Phone Number: Click or tap here to enter text.

Incident Type

☐ Reportable Cyber Security Incident

☐ Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part

Reporting Category

☐ Initial Notification

☐ Update

Required Attribute Information

1. Attack Vector ☐ Initial ☐ Update

Click or tap here to enter text.

2. Functional Impact ☐ Initial ☐ Update

Click or tap here to enter text.

3. Level of Intrusion ☐ Initial ☐ Update

Click or tap here to enter text.

Instructions for Example of a Reporting Form

These are instructions on how to complete the optional form

CIP-008-6
Cyber Security Incident Reporting Form Instructions

CIP-008-6– Reportable Cyber Security Incident Reporting Form Instructions		
Form Section	**Field Name**	**Instructions**
Contact Information	**Name**	Enter the First and Last Name of the Responsible Entity's primary point of contact for the reported incident.
	Phone Number	Enter the Phone Number(s) of the Responsible Entity's primary point of contact for the reported incident.
Incident Type	**Reportable Cyber Security Incident**	Check this box if report includes information for a Reportable Cyber Security Incident.
	Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part	Check this box if report includes information for a Cyber Security Incident that attempted to compromise a system identified in the "Applicable Systems" column for the Part Note: Do not check this box for incidents related solely to a PSP(s).
Reporting Category	**Initial Notification**	Check this box if report is being submitted to satisfy initial notification obligations of Requirement R4 Part 4.2.
	Update	Check this box if report is being submitted to satisfy subsequent follow-up or update obligations of Requirement R4 Part 4.3.
Required Attribute Information (Attack Vector fields)	**Attack Vector**	• If known, enter a narrative description of the Attack Vector for the compromise or attempt to compromise to satisfy the required attribute specified in Requirement R4 Part 4.1. • If not known, specify 'unknown' in the field. *Examples include, but are not limited to, malware, use of stolen credentials, etc.*

CIP-008-6– Reportable Cyber Security Incident Reporting Form Instructions		
Form Section	**Field Name**	**Instructions**
	Attack Vector Initial Checkbox	If report is being used to provide the preliminary report, select the 'Initial' checkbox.
	Attack Vector Update Checkbox	If report is being used to provide an update report, select the 'Update' checkbox.
Required Attribute Information (Functional Impact fields)	**Functional Impact**	• If known, enter a narrative description of the functional impact for the compromise or attempt to compromise to satisfy the required attribute specified in Requirement R4 Part 4.1. • If not known, specify 'unknown' in the field. *Examples include, but are not limited to, situational awareness, dynamic response, ability to perform Real-time Assessments, or Real-time monitoring etc.*
	Functional Impact Initial Checkbox	If report is being used to provide the preliminary report, select the 'Initial' checkbox.
	Functional Impact Update Checkbox	If report is being used to provide an update report, select the 'Update' checkbox.
Required Attribute Information (Level of Intrusion fields)	**Level of Intrusion**	• If known, enter a narrative description of the level of intrusion for the compromise or attempt to compromise to satisfy the required attribute specified in Requirement R4 Part 4.1. • If not known, specify 'unknown' in the field. *Examples include, but are not limited to, whether the compromise or attempt to compromise occurred on Applicable Systems outside the Electronic Security Perimeter (ESP), at the ESP, or inside the ESP. Additionally, level of intrusion may include the Applicable System impact level and Cyber System classification level.*
	Level of Intrusion Initial Checkbox	If report is being used to provide the preliminary report, select the 'Initial' checkbox.
	Level of Intrusion Update Checkbox	If report is being used to provide an update, select the 'Update' checkbox.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



Reliability Functional Model Technical Document

Version 5.1

Prepared by the Functional Model ~~Working~~ Advisory Group

This document is a companion to Version 5.1 of the Functional Model. It provides context, explanations, opinions, and discussions on various aspects of the Functional Model.

~~Approved~~ Endorsed by Standing Committees~~Operating, Planning and Critical Infrastructure Protections Committees~~: ~~December 2009~~
~~Approved~~ Endorsed by Standards Committee: ~~January 2010~~
~~Approved by Board of Trustees: May 2010~~

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Table of Contents

Table of Contents....3
Introduction....5
Section I — Entity ~~Task~~Tasks~~s~~ and Interrelationships....6
1. Reliability Coordinator....7
2. Balancing Authority....9
3. Planning Coordinator....11
4. Transmission Planner....13
5. Resource Planner....14
6. Transmission Operator....15
7. ~~Interchange Coordinator~~Interchange Authority....18
8. Transmission Service Provider....20
9. Transmission Owner....21
10. Distribution Provider....22
11. Generator Operator....23
12. Generator Owner....24
13. Purchasing-Selling Entity....25
14. Load-Serving Entity....26
15. Compliance Enforcement Authority....27
16. Standards Developer....28
17. Market Operator (Resource Integrator)....29
18. Reliability Assurer....30
Section II — Technical Discussions....31
1. General Clarifications of the Functional Model....32
2. Reliability Standards....36
3. Market Operations (Resource Integration)....38
4. The Functional Model and Market Structures....40
5. Providing and Deploying Ancillary and Reliability-Related Services....42
6. Managing Bilateral Interchange Transactions — Basic Concepts....44
7. Managing Bilateral Interchange — Scheduling ~~Agents~~Entity....47
8. Non-coincident Resource Integrator and Balancing Authority Areas....48
9. Implementing the ~~Interchange Coordinator~~Interchange Authority....50
10. Distribution Provider as Load-Serving Entity....53
Error! Hyperlink reference not valid.
~~11. Terminology Changes in Version 5....56~~

11. Reliability Areas and Boundaries 63
12. Generating versus Transmission Assets 65
13. Roles in Load Curtailment 66
14. History of Revisions 69

Introduction

This document is intended as a companion to Version 5.1 of the Functional Model (Model) to help the reader better understand the Model's Functions, Ffunctional Eentities and their relationships. This document therefore provides context, explanation and opinions. It is a companion to, rather than a formal part of, Version 5.1 of the Model.

Section I provides details about each of the ~~Responsible~~ Functional Entities. Some entities, such as the Transmission Owner or Purchasing-Selling Entity, are adequately described in the ~~Functional~~ Model document, and there is little detail to add here. Others, such as the Interchange Coordinator Authority(ies) and Balancing Authority(ies), are more complex both unto themselves and in their relationship with other entities, and this document provides additional explanations.

Section II includes technical discussions on related topics such as managing Arranged and Confirmed Interchange, and Ffunctional Eentity boundary conditions. The discussion of Market Operations illustrates that the Model applies to different market structures.

Section I — Entity Tasks and Interrelationships

Version 4 of the Model, issued in 2008, clarified the concept of *responsibility* in the Model, as reflected in the use of the term Responsible Entity. In particular, it was clarified that while there were responsibilities of the entities in the FunctionFunctional Model *within the context of the Model itself*, the responsibilities that will actually apply to an organization will be determined within NERC's registration, certification and compliance processes and Reliability Standards, not by the Model.

However, it subsequently became apparent to the FunctionFunctional Model Working Group that having two different contexts for responsibility did not completely eliminate the potential for confusion. On this basis, Version 55.1 goes one step further and eliminates reference to *responsibility* within the Model, replacing the term *responsible entity* with the term *functionFunctional Eentity*. In Version 55.1 of the Model, an entity is defined by the Ffunctions it performs.[1]

As a result of refocusing the Model on TaskTasks rather than responsibility, Version 55.1 of the Technical Document has removed discussions associated with responsibility of individual organizations. These matters are now addressed within the context of NERC's registration and compliance programs, typically within NERC's Rules of Procedure. These include situations where:

- an organizations may "bundle" a number of different functionFunctions and register as the corresponding functionFunctional entities, for example Reliability Coordinator and Transmission Operator
- two or more organizations may register jointly with NERC as functionFunctional entities and thereby divide or share responsibility for meeting standards requirements (Joint Registry Organizations)
- an organization may register and assume responsibility for TaskTasks performed by others, such as a rural cooperative on behalf of its members.



[1] Version 5 of the Model uses the term "functionFunctional entityFunctional Entity" to apply to the *entity described in the FunctionFunctional Model* (Balancing Authority, etc.). It is proposed that other NERC documents follow this usage, and also that they use the terms "registered entity", "certified entity" and "responsible entity", in reference to *specific organizations*. For example, PJM is a registered entity and certified entity for the Balancing Authority functionFunctional entityFunctional Entity.

1. Reliability Coordinator

The Reliability Coordinator's purview must be broad enough to enable it to calculate Interconnection Reliability Operating Limits, which will involve system and facility operating parameters beyond its own Area as well as within it. This is in contrast to the Transmission Operator, which also maintains reliability, but is directly concerned with system parameters within its own Area.

The Reliability Coordinator is the highest operating authority; the underlying premise is that reliability of a wide-area takes precedence over reliability of any single local area. Only the Reliability Coordinator has the perspective/vision necessary to act in the interest of wide-area reliability.

The Reliability Coordinator also assists the Transmission Operator in relieving equipment or facility overloads through transmission loading relief measures if market-based dispatch procedures are not effective.

Role in Interchange. The Reliability Coordinator does not receive tags, but may curtail Interchange Transactions until they are arranged and ready for implementation as Interchange Schedules. As such, it does not approve or deny tags. However, once the Reliability Coordinator receives the Interchange Schedule information, it will have the necessary information to aid its assessment of the impacts of flowing and impending Transaction Schedules on its area's reliability. As necessary, the Reliability Coordinator may issue transmission loading relief requests (or similar requests for congestion management) which may result in reducing, removing or halting flowing or impending Interchange Transactions. This is viewed by some as "denying" the Interchange Transactions although in this context, the "denial" is not provided during the collection of approval stage.

Day-ahead analysis. The Reliability Coordinator will receive the dispatch plans from the Balancing Authority(ies) on a day-ahead basis. The Reliability Coordinator will then analyze the dispatch from a transmission reliability perspective. If the Reliability Coordinator determines that the Balancing Authority's dispatch plans will jeopardize transmission reliability, the Reliability Coordinator will work with the Balancing Authority(ies) to determine where the dispatch plans need to be adjusted. The Reliability Coordinator obtains generation and transmission maintenance schedules from Generator Operators and Transmission Operators. The Reliability Coordinator can deny a transmission outage request if a transmission system reliability constraint would be violated.

The Transmission Operator is responsible for the reliability of its "local" transmission system in accordance with maintaining System Operating Limits (SOLs). However, in some circumstances, as noted above for reliability analysis associated with generation dispatch instructions, the Reliability Coordinator may become aware of a potential SOL violation and issue a dispatch adjustment. Therefore, in this context, the Reliability Coordinator also has a role regarding the Transmission Operator's management of SOLs.

Emergency actions. The Reliability Coordinator is responsible for Real-time system reliability, which includes calling for the following emergency actions:

- Curtailing Interchange Schedules

- Directing redispatch to alleviate congestion
- Mitigating energy and transmission emergencies
- Ensuring energy balance and Interconnection frequency
- Directing load shedding.

The Reliability Coordinator, in collaboration with the Balancing Authority(ies) and Transmission Operator, can invoke public appeals, voltage reductions, demand-side management, and even load shedding if the Balancing Authority(ies) cannot achieve resource-demand balance.

System restoration actions. The Reliability Coordinator directs and coordinates system restoration with Transmission Operators and Balancing Authority(ies).

Authority to perform its reliability functions. The Reliability Coordinator's authority is documented in one or more regional reliability plans, as applicable, for the Region in which the Reliability Coordinator Area is located. In cases where a Reliability Coordinator Area spreads over multiple Regions, its authority will be documented in and accepted by all the concerned Regions through their respective reliability plans.

In addition, since the Reliability Coordinator may also have a role regarding the Transmission Operator's management of SOLs, delineation of its authority and that of the Transmission Operator needs to be clearly defined in the reliability plan(s).

2. Balancing Authority

The Balancing Authority(ies) operates within the metered boundaries that establish the **Balancing Authority Area**. Every generator, transmission facility, and ~~e~~End-use ~~c~~Customer is in a Balancing Authority Area. The Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority(ies) Area by keeping its actual interchange equal to its scheduled interchange and meeting its frequency bias obligation. The load-resource balance is measured by the Balancing Authority's Area Control Error (ACE).

NERC's Reliability Standards require that the Balancing Authority(ies) maintain its ACE within acceptable limits.

Maintaining resource-demand balance within the Balancing Authority(ies) Area requires four types of resource management, all of which are the Balancing Authority's responsibility:

- Frequency control through tie-line bias
- Regulation service deployment
- Load-following through economic dispatch
- Interchange implementation

Frequency control through tie-line bias. To maintain frequency within acceptable limits, the Balancing Authority(ies) controls resources within its Balancing Authority Area to meet its frequency bias obligation to the interconnection.

Regulation service deployment. To maintain its ACE within these acceptable limits, the Balancing Authority(ies) controls a set of generators within its Balancing Authority(ies) Area that are capable of providing regulation service.

Load-following through economic dispatch. The organization that serves as the Balancing Authority(ies) will in general also perform unit commitment and economic dispatch; however, in some markets, Generator Operators may be permitted to perform unit commitment and economic dispatch among the fleet of generators under their control and within the requirements accepted by the market operator.

Interchange implementation. The Balancing Authority(ies) receives Confirmed Interchange from one or more Interchange ~~Coordinator~~ Authority(ies), and enters those Interchange Schedules into its energy management system.

Unit commitment and schedules from Load-Serving Entities. The Balancing Authority(ies) receives resource dispatch plans from the Market Operator and/or unit commitment and dispatch schedules from the Load-Serving Entities that have bilateral arrangements for generation within the market or the Balancing Authority(ies) Area. The Balancing Authority(ies) provides this commitment and dispatch schedule to the Reliability Coordinator.

Role in approving Interchange. The Balancing Authority(ies) approves an Arranged Interchange with respect to the ramping requirements of the generation that must increase or decrease to implement the Interchange. The Balancing Authority(ies) provides its approval or denial to the Interchange Coordinator Authority(ies).

Energy Emergencies. In the event of an Energy Emergency, the Balancing Authority(ies) can implement public appeals, demand-side management programs, and, ultimately load shedding. **Obviously, it must do this in concert with the Reliability Coordinator.**

Failure to balance. The Balancing Authority(ies) must take action, either under its own initiative or direction by the Reliability Coordinator, if the Balancing Authority(ies) cannot comply with NERC's Reliability Standards regarding frequency control and Area Control Error.

See "Managing Bilateral Interchange Transactions"

3. Planning Coordinator

The Planning Coordinator coordinates and integrates transmission facility and service plans, resource plans, and protection system plans among the Transmission Planner(s) and Resource Planner(s) within its area of purview. These activities range from review and integration of reinforcement and corrective action plans developed by the ~~f~~Functional ~~e~~Entities whose area of responsibility is within the Planning Coordinator's area with respect to established reliability needs to providing procedures, protocols, modeling and methodology software, etc. for consistent use within its area.

While much of what the Planning Coordinator performs could be actually performed by a Transmission Planner, such as developing methodologies in conjunction with surrounding Transmission Planners, recognition of resource plans, assessing system performance consistent with reliability needs by itself, and collaborating with other Transmission Planners to assess impacts on the interconnected area, the Planning Coordinator by its very nature will generally take responsibility over a wider perspective than the Transmission Planners for which its coordinates. The Planning Coordinator generally conducts system performance assessments, in collaboration with other Planning Coordinators to consider transfer/flows across multiple Transmission Planner areas or intra and interstate areas such as generation dispatch scenarios caused by temperature or fuel extremes. Geographic size is not necessarily a critical consideration, it is the extent and impact of the electrical network that the planners have taken responsibility for assessing that determines whether an area is large enough for analysis and planning.

Although the ~~Functional~~ Model sets forth the concept of the Planning Coordinator and how a functional entity could perform as such, there may be situations or circumstances under actual organizational structures whereby a single entity does not exist that performs the Reliability Planning Function but rather is taken on by a number of entities, e.g. a group of Transmission Planners, or an organization such as a regional group formed within a region or possibly the Regional Entity itself. In all these cases the Reliability Planning Function is still performed in some manner by some entity or organization.

The boundaries for the Planning Coordinator area are basically defined by the location of the Bulk Electric System (BES) ~~f~~Facilities under the purview of the Planning Coordinator, i.e. those ~~f~~Facilities for which the Planning Coordinator coordinates and evaluates and recommends reinforcement and corrective plans resulting from studies and analysis of system performance and interconnection of ~~f~~Facilities. The BES ~~f~~Facilities under its purview~~,~~ are generally contiguous and cover in aggregate the same areas as the Transmission Planners its coordinates. Traditionally transmission planning has been associated with one or more Transmission Owners, i.e. reinforcement and corrective action plans must be associated with certain Transmission Owner ~~f~~Facilities. Since transmission ownership may cross state or provincial or regional boundaries, the BES ~~f~~Facilities on one side of the Transmission Owner boundary may be in one Planning Coordinator area whereas the remaining ~~f~~Facilities may be in another. As such the Planning Coordinator area is not constrained to fit within a Reliability Coordinator or Transmission Operator Area. However, the Planning Coordinator area must cover at least one Transmission Planner Area and one Resource Planner area, or part thereof if either or both of these planner areas is larger than the Planning Coordinator area. On the other hand, there is the possibility that a Planning Coordinator area could be nested inside an even larger Planning

Coordinator area provided the smaller Planning Coordinator does in fact perform the appropriate system assessments. In this special case, the larger Planning Coordinator would perform the ultimate planning coordinating function for all the Resource Planners, Transmission Planner and smaller Planning Coordinator in its Area. As an example, some Independent System Operators (ISO) and Regional Transmission Organizations (RTO) perform the Reliability Planning Functions but they are also under the purview of the Regional Entity that also performs the Reliability Planning Function at a broader scale.

In many areas, there may exist more than one Transmission Planner and Resource Planner, as well as a nested Planning Coordinator, within a Planning Coordinator area, each performing a different role demarcated primarily by their particular ~~f~~Function and scale (area-wise) of assessments performed. In these cases, delineation of the role of the various F~~f~~unctional Ee~~e~~ntities needs to be clearly defined in the regional reliability plan(s).

The Planning Coordinator is not responsible for implementing the transmission and resource plans. However, it helps to facilitate the process whereby adequate resources and transmission facilities are placed into service in a timely manner through the Resource Planners, Transmission Planners, and possibly others through the coordinated planning process.

4. Transmission Planner

The Transmission Planner develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area ~~of purview~~.

The boundaries for the Transmission Planner area are basically defined by the location of the BES~~Bulk Electric System~~ ~~f~~Facilities under the purview of the Transmission Planner, i.e. those facilities for which the Transmission Planner develops reinforcement and ~~c~~Corrective ~~a~~Action ~~p~~Plans resulting from studies and analysis of system performance and interconnection of facilities. This means that the Transmission Planner's area is not defined by the extent of the models it uses or studies that it performs since any planner can assess and perform simulations on readily available ~~i~~Interconnection wide models. The BES facilities in its area, i.e. under its purview, are generally contiguous.

Traditionally transmission planning has been associated with one or more Transmission Owners, i.e. reinforcement and ~~c~~Corrective ~~a~~Action ~~p~~Plans must be associated with the facilities of certain Transmission Owners. In some cases where transmission ownership crosses a state line, the BES facilities on one side of a geographic boundary line may be in one Transmission Planner ~~A~~area while the remaining facilities may be in another. As such, the Transmission Planner ~~A~~area is not constrained to fit within one Reliability Coordinator or Transmission Operator Area. However, the Transmission Planner ~~A~~area can only be smaller than or equal to the area of its related Planning Coordinator.

Develop Transmission Expansion Plans. The Transmission Planner evaluates the facilities that will be needed in response to long-term requests for ~~t~~Transmission ~~s~~Service, and needed to integrate new generation, transmission, and ~~e~~End-use ~~c~~Customers into the BES~~Bulk Electric Systems~~. In developing plans for ~~t~~Transmission ~~s~~Service and interconnection requests, the Transmission Planner is expected to coordinate plans or engage in joint planning with other Transmission Planners, as appropriate, to ensure new facilities do not adversely affect the reliability of neighboring transmission systems.

Based on customer requests for ~~t~~Transmission ~~s~~Service, ~~n~~Native ~~l~~Load growth, changes in existing ~~n~~Native ~~l~~Load, and the planning procedures and protocols established for their Transmission Planning ~~A~~areas, the Transmission Planners will develop transmission plans to accommodate long-term ~~f~~Firm ~~t~~Transmission ~~s~~Service requests and ~~n~~Native ~~l~~Load requirements with due regard to established reliability needs. While developing these plans, the Transmission Planner may provide alternate solutions and evaluate alternatives suggested by entities requesting customer service.

The Transmission Planner~~s~~ provide~~s~~ its transmission plans to its Planning Coordinator for review to ensure impacts on the interconnected systems are duly addressed. In reporting its transmission expansion plan to the Planning Coordinator, the Transmission Planner is expected to assess whether its plans for new or reinforced facilities meet reliability needs or whether ~~c~~Corrective Action ~~p~~Plans are necessary. The Transmission Planners work with the Planning Coordinator to identify potential alternative solutions, including solutions proposed by stakeholders, to meet interconnected BES~~Bulk Electric System~~ requirements.

5. Resource Planner

The Resource Planner develops a long-term (generally 1 year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Resource Planner area.

Note: The term "resource" is to be understood to include supply resources and demand resources (such as dispatchable loads).

The boundaries for the Resource Planner area are basically defined by the location of the specific loads being considered for resource adequacy. The loads under considerations are generally contiguous and form the fundamental input for analysis of resources such as loss of load studies. The Resource Planning Ff~~f~~unction may be performed by one or more Resource Planners within a Planning Coordinator area, Transmission Planner or Reliability Coordinator Area; however, the Resource Planning Function could be performed by one Resource Planner that covers one, or more than one, Planning Coordinator area, Transmission Planner Area or Reliability Coordinator Area. As such the Resource Planner area is not constrained to fit within the footprint of any other ~~f~~Functional Ee~~e~~ntity. The analysis and development of resource plans by their very nature will need to consider generation capacity and other resources outside the area defined by the specific loads as well as the transmission capability to access those resources.

In some markets, market rules may require the same organization to assume the role of both the Planning Coordinator and the Resource Planner. For example, in those markets where there are no entities responsible for or obligated to serve load, the Planning Coordinator will generally assume the Resource Planner's role. In these cases, the Planning Coordinator identifies the need for additional resources to be provided by the market and performs the Resource Planning Function.

Types of Resource Planning
Resource planning, in a generic sense, may be divided into two types:

- Planning conducted by an organization under the authority of legislation, regulation order, tariff or market rule. Such planning will typically be conducted in an open process and subject to industry, public and stakeholder review. It will have as one objective, ensuring resource adequacy.
- Planning directed to identifying and realizing commercial opportunities. Such plans will typically be commercially sensitive, may not be made public before required for the plan to be implemented, and will not be directed to ensuring resource adequacy.

The Resource Planner described in the Model is associated with the former type of planning, i.e., planning having a mandate to ensure resource adequacy.

The latter type of planning, which is driven primarily by commercial opportunity, may be viewed as an activity associated with generation ownership. However, resource planning that is purely commercially-driven clearly will have an impact on resource adequacy. The Resource Planner, with its mandate for resource adequacy, must reflect to the extent possible commercially-directed planning affecting its Resource Planner area.

6. Transmission Operator

The Transmission Operator operates or directs the operation of transmission facilities, and maintains local-area reliability, that is, the reliability of the system and area for which the Transmission Operator has responsibility. The Transmission Operator achieves this by operating the transmission system within its purview in a manner that maintains proper voltage profiles and System Operating Limits, and honors transmission equipment limits established by the Transmission Owner. The Transmission Operator is under the Reliability Coordinator's direction respecting wide-area reliability considerations, that is, considerations beyond those of the system and area for which the Transmission Operator has responsibility and that include the systems and areas of neighboring Reliability Coordinators. The Transmission Operator, in coordination with the Reliability Coordinator, can take action, such as implementing voltage reductions, to help mitigate an Energy Emergency, and can take action in system restoration.

Note that the Model does not attempt to define what is and isn't a transmission facility, versus a generating facility. As discussed in Section II-13, this is assumed to be defined elsewhere by NERC or by governmental authorities.

Maintenance. The Transmission Owner provides the overall maintenance plans and requirements for its equipment, specifying, for example, maintenance periods for its transformers, breakers, and the like. The Transmission Owner then develops or arranges for the development of the detailed maintenance schedules (dates and times) based on the Transmission Owner's maintenance plans and requirements, and provides those schedules to the Reliability Coordinator and others as needed.

The organization serving as Transmission Operator may also physically provide or arrange for transmission maintenance, but it does this under the direction of the Transmission Owner, which is ultimately responsible for maintaining its owned transmission facilities.

Bundled with the Reliability Coordinator or Transmission Owner. A single organization may be the F~~f~~unction E~~e~~ntity for multiple Functions. In such a case, the F~~f~~unctional Entities are said to be "rolled up" or "bundled" into a single organization. An organization may be a Transmission Operator without being a Reliability Coordinator or Transmission Owner. However, in many cases the Transmission Operator is bundled with one of these F~~f~~unctional ~~e~~Entities.

Bundled with Reliability Coordinator. For example, consider an RTO with several members. The RTO registers with NERC as a Reliability Coordinator and Transmission Operator and is NERC-certified for both. The RTO then delegates/assigns some of the Transmission Operator ~~T~~tasks to its members.

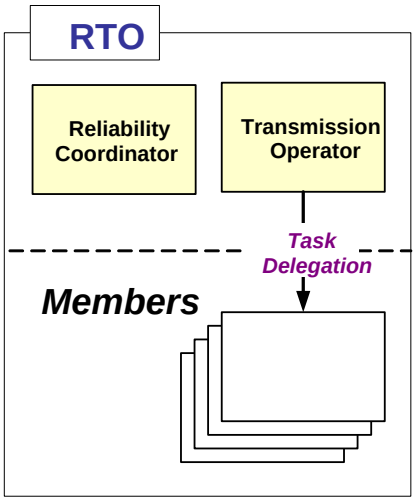


Figure 1 - Transmission Operator bundled with Reliability Coordinator.

Bundled with the Transmission Owner. In other situations, the RTO registers with NERC as the Reliability Coordinator, and its members register as Transmission Owners and Transmission Operators, as shown in Figure 2. In this case, the Model views the RTO as responsible for complying with Reliability Standards associated with the Reliability Coordinator and would be NERC-certified as such. The RTO members would be responsible for complying with all Reliability Standards associated with the Transmission Operator, and would be NERC-certified as such.

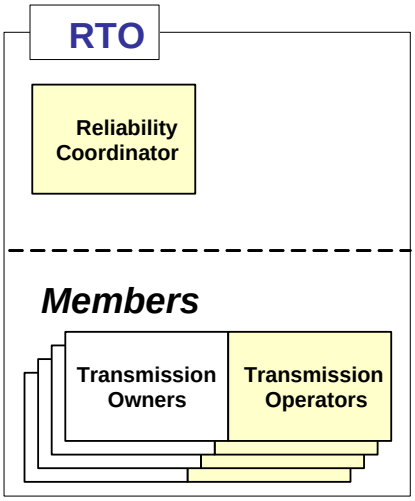


Figure 2 – Transmission Operator bundled with Transmission Owner

7. Interchange ~~Coordinator~~ Authority

The Interchange ~~Coordinator~~ Authority(ies) collects approvals or denials for Arranged Interchange from Balancing Authorities and Transmission Service Providers and verifies the validity of the source and sink. The NERC Tag Authority provides this service that had been assigned to the Sink Balancing Authority(ies).

The Interchange ~~Coordinator~~ Authority(ies) provides the Balancing Authority(ies) with the individual bilateral Arranged Interchange. The Balancing Authority(ies) must track the individual Interchange Schedules in case one or more of them are curtailed by the Reliability Coordinator or by the Balancing Authority(ies) in those cases where a generator or load is interrupted. The Balancing Authority(ies) then creates a "net" interchange total for use in its energy management system as well as a "net" interchange for each neighboring Balancing Authority(ies). The net Interchange Schedule for each neighboring Balancing Authority(ies) is used by the Receiving Balancing Authority(ies) for checkout with the neighboring Balancing Authority(ies).

All bilateral Interchange Transactions *that cross a Balancing Authority*(ies) *Area boundary* are coordinated through the Interchange ~~Coordinator~~ Authority(ies).

While the approval/denial process may utilize tools (such as computer software and communication protocols), the Model envisages that the Interchange F~~f~~unction will be assigned to an actual organization. A Balancing Authority(ies) may serve as its own Interchange ~~Coordinator~~ Authority(ies) or have this service provided by a separate organization.

Assessing ramping capability and connectivity. The Balancing Authority(ies) approves/denies the capability to ramp the Arranged Interchange in or out and notifies the Interchange ~~Coordinator~~ Authority(ies). The connectivity of adjacent Balancing Authorities is also verified by the Balancing Authorities before responding to the Interchange ~~Coordinator~~ Authority(ies).

Ensuring balanced, valid Interchange Transactions. The Interchange ~~Coordinator~~ Authority(ies) also ensures that the resulting Confirmed Interchange Transactions is balanced and valid prior to physical delivery. This means:

- The source MW must be equal to the sink MW (plus losses if they are "self-provided"), and
- All reliability entities involved in the Arranged Interchange are currently in the NERC registry.

Only when it receives approvals from the Transmission Service Providers and Balancing Authorities, does the Interchange ~~Coordinator~~ Authority(ies) direct the Balancing Authorities to implement the Transaction. If any of these entities — TSPs, or BAs — does not approve the Arranged Transaction, then the Interchange ~~Coordinator~~ Authority(ies) does not authorize the Transaction to become Confirmed Interchange.

Curtailments. The Interchange ~~Coordinator~~ Authority(ies) coordinates ~~c~~Curtailments of Confirmed Interchange ordered by the Reliability Coordinator by notifying the Balancing Authorities, Transmission Service Providers, and Purchasing-Selling Entities. The Interchange ~~Coordinator~~

Authority(ies) also communicates and coordinates the resulting modified Arranged Interchange that result from the ~~c~~Curtailments.

8. Transmission Service Provider

The Transmission Service Provider authorizes the use of the transmission system under its authority. In most cases, the organization serving as Transmission Service Provider is also the market operator.

Role in approving Interchange. The Transmission Service Provider approves Arranged Interchange by comparing the ~~t~~Transmission ~~s~~Service previously arranged by the ~~t~~Transmission customer ~~(Purchasing-Selling Entity, Generator Owner, Load-Serving Entity)~~ with the transmission information supplied by the Interchange ~~Coordinator~~ Authority(ies). The Transmission Service Provider also ensures that there is a contiguous transmission path and that adjacent TSPs are on the scheduling path. The Transmission Service Provider then provides its approval or denial to the Interchange ~~Coordinator~~ Authority(ies).

Providing Transmission Service. As its name implies, the Transmission Service Provider provides ~~t~~Transmission ~~s~~Service to ~~t~~Transmission ~~c~~Customers, such as Generator Owners, Load-Serving Entities, and Purchasing-Selling Entities. The Transmission Service Provider determines Available Transfer Capability based on the established Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits (by various entities including the Planning Coordinator, Transmission Planner, Transmission Operator and Reliability Coordinator), and coordinates ATC with other Transmission Service Providers. The Transmission Service Provider manages the requests for ~~t~~Transmission ~~s~~Service according to the Transmission Owner's tariff, and within the operating reliability limits determined by the Reliability Coordinator. The Transmission Service Provider does not itself have a role in maintaining system reliability in real time — that is done by the Reliability Coordinator and Transmission Operator.

The Transmission Service Provider arranges for transmission loss compensation with the Balancing Authority(ies).

9. Transmission Owner

The Transmission Owner owns its transmission ~~f~~Facilities and provides for the maintenance of those facilities. It also specifies equipment operating limits, and supplies this information to the Transmission Operator, Reliability Coordinator, and Transmission Planner and Planning Coordinator.

In many cases, the Transmission Owner has contracts or interconnection agreements with generators or other ~~t~~Transmission ~~c~~Customers that would detail the terms of the interconnection between the owner and customer.

Relationship with the Transmission Operator. The organization serving as Transmission Owner may operate its transmission ~~f~~Facilities or arrange for another organization (which may or may not be a Transmission Owner) to operate and/or maintain its transmission ~~f~~Facilities.

See "Transmission Operator," Section "Bundling with the Reliability Coordinator or Transmission Owner"

10. Distribution Provider

The Distribution Provider provides the physical connection between the ~~e~~End-use ~~c~~Customers and the electric system, including customers served at transmission level voltages. The Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution ~~f~~Function at any voltage. One Distribution Provider may be directly connected to another Distribution Provider and not directly connected to the B~~ulk E~~~~lectric S~~~~ystem~~.

The Distribution Provider maintains "local" safety and reliability. The Distribution Provider provides the switches and re-closers necessary for emergency action. The Distribution Provider may need to demonstrate load-shedding capability to the Balancing Authority(ies) and Transmission Operator.

The same organization may serve as the Distribution Provider and Load-Serving Entity, but they may be separate organizations as well. Unlike the Load-Serving Entity, the Distribution Provider has the facilities or assets ("wires") and does not take title to any energy. However, while these ~~f~~Functions are distinct, in many cases an organization, such as a vertically integrated utility, bundles these ~~f~~Functions together.

11. Generator Operator

The Generator Owner may operate its generating ~~f~~Facilities or designate a separate organization to perform the Generator Operation Function.

The Generator Operator operates, or directs the operation of generation ~~f~~Facilities. The Generator Operator supports the needs of the BES~~Bulk Electric System~~ up to the limits of the generating ~~f~~Facilities in its purview. Ultimately the Generator Operator's role is to meet generation schedules, manage fuel supplies, and provide frequency support and reactive resources without jeopardizing equipment.

Relationship with the Generator Owner. The organization that serves as Generator Operator may also be the owner of the generation ~~f~~Facilities it operates; or it may be a separate organization designated by the Generator Owner to operate the ~~f~~Facilities. The Generator Operator receives maintenance and performance verification schedules from the Generator Owner, and develops operating and unit commitment plans based on these schedules.

Relationship with the Transmission Operator. The Generator Operator provides Interconnected Operations Service~~reliability-related services~~ through arrangements or by direction from the Transmission Operator for support of the BES~~Bulk Electric System~~. The Generator Operator provides maintenance schedules, generator status, and AVR status to the Transmission Operator. The Generator Operator receives notification of transmission system problems affecting its generator from the Transmission Operator or Reliability Coordinator.

Relationship with the Balancing Authority(ies). The Generator Operator provides unit commitment schedules, generator status, and operating and availability status of generating units to the Balancing Authority(ies).

Relationship with the Reliability Coordinator. The Generator Operator provides annual maintenance plans, and operational data to the Reliability Coordinator. The Generator Operator takes actions based on directives from the Reliability Coordinator for the needs of the B~~ulk~~ E~~lectric~~ S~~ystem~~.

Relationship with Purchasing-Selling-Entity. The Generator Operator receives notice of Arranged Interchange approved by the Purchasing-Selling-Entity.

12. Generator Owner

The Generator Owner owns its generation ~~f~~Facilities and provides for the maintenance of those ~~f~~Facilities. It also provides verified equipment operating limits and supplies this information to the Generator Operator, Reliability Coordinator, Transmission Planner and Planning Coordinator.

In many cases, the Generator Owner has contracts or interconnection agreements with Transmission Owners or Distribution Providers that detail the terms of the interconnection between these parties.

Relationship with the Generator Operator. The organization serving as Generator Owner may operate generation ~~f~~Facilities, or arrange for another organization to do so. In addition, the organization serving as Generator Owner may perform maintenance and ~~f~~Facility verification, or may arrange with another organization to do so.

13. Purchasing-Selling Entity

The Purchasing-Selling Entity (PSE) arranges for and takes title to energy products (capacity, energy and reliability-related services) that it secures from a resource for delivery to a Load-Serving Entity (LSE). The PSE also arranges for ~~t~~Transmission ~~s~~Service with the Transmission Service Provider that provides ~~t~~Transmission ~~s~~Service to the LSE under a tariff or market rule.

The Purchasing-Selling Entity initiates a bilateral Interchange between Balancing Authority(ies) Areas by submitting a Request for Interchange (RFI) to the Interchange ~~Coordinator~~ Authority(ies).

14. Load-Serving Entity

The Load-Serving Entity (LSE) arranges for the provision of energy to its ~~e~~End-use ~~c~~Customers, but does not provide distribution services ("wires"). The LSE defined in the Model is not to be confused with or equated to the LSE as defined in any tariff or market rule.

Today, organizations serving as Load-Serving Entities may also be Generation Owners and can self-provide, or have contracts with other Generator Owners for capacity and energy to serve the LSE's customers, or purchase capacity and energy from non-affiliated Generator Owners through a Purchasing-Selling Entity (or Market Operator), or employ a combination of these three options.

The Load-Serving Entity reports its generation (affiliated and non-affiliated) arrangements to serve load to the Balancing Authority(ies), which forwards this information to the Reliability Coordinator, for day-ahead analysis.

The LSE may contract for reliability-related services through the Market Operator (if the LSE is part of a market or pool) or directly from Generator Owners or loads.

The same organization may serve as the Distribution Provider and Load-Serving Entity, but they may be separate organizations as well. Unlike the Distribution Provider, the Load-Serving Entity, does not have ~~Bulk Electric System~~BES assets ("wires") but does take title to energy. However, while these ~~f~~Functions are distinct, in many cases an organization, such as a vertically integrated utility, bundles these ~~f~~Functions together.

The ~~Functional~~ Model assigns to the LSE the identification of loads for ~~c~~Curtailment and the development of load profiles and load forecasts. Please see Section II, 114: Roles in Load Curtailment for more detailed information.

The LSE communicates requests for voluntary ~~c~~Curtailment to the appropriate ~~e~~End-use ~~c~~Customer loads, thereby ensuring that these loads will in fact be curtailed.

15. Compliance Enforcement Authority

NERC is the Compliance Enforcement Authority. The Regional Entities have a major role in the actual performance of the monitoring, under delegated authority from NERC.

16. Standards Developer

The Standards Developer is written to be NERC. The Reliability Standards referenced in the Model consist of standards developed by either NERC or a Regional Entity and that are approved by NERC and subsequently by governmental authorities. This would therefore not include regional reliability criteria that are not submitted to NERC for approval. This is discussed further in Section II.

17. Market Operator (Resource Integrator)

Market Operations is not a reliability Function. It is included in the Model to provide a linkage between reliability Functions and commercial functions.

The associated Ffunctional Eentity is the Market Operator (Resource Integrator). ~~The term Resource Integrator replaces Resource Dispatcher used in Version 3 of the Model.~~ This recognizes that integration of resources is the essential feature, not resource dispatch, which is the responsibility of the Balancing Authority(ies).

The Market Operator is described further in Section II, Technical Discussions.

18. Reliability Assurer

~~In Version 4 of the Model, the Reliability Assurer entity and the Reliability Assurance Function~~ Function ~~replaced Version 3's Regional Reliability Organization entity and the Regional Reliability Assurance Function~~Function~~.~~

~~The change to~~ Use of the term Reliability Assurer ~~reflected~~ reflects the fact that ~~a name specific to the Model is preferable to a name already in use in another context. Moreover, since~~ this ~~-~~Function can be performed on other than a regional basis, the ~~Functional~~ Model allows for the assignment to be made to an organization other than a Regional Entity.

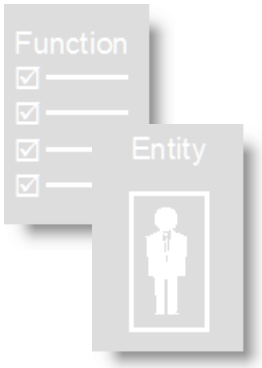
~~The changes therefore provide NERC with flexibility in assigning the F~~functional ~~E~~entity ~~for Reliability Assurance.~~

The role of the Reliability Assurer may be considered to provide "defense-in-depth". That is, the Reliability Assurer provides an independent assessment of ~~T~~task ~~performed~~ by other ~~F~~functional ~~e~~ntities~~, or facilitates or coordinates such Task~~. While the specific role of the Reliability Assurer is not fully developed at the present time, the following are representative of the ~~T~~tasks that might be performed:

- Perform high level evaluations, such as at a regional or ~~i~~interconnection level, of transmission and resource adequacy. These evaluations may be based on a review of the plans of Transmission Planners.
- Develop regional reliability plans, to ensure there are no reliability gaps, or no missing or ambiguous responsibilities or relationships.
- Perform high-level evaluations, such as at a regional or ~~i~~interconnection level, of ~~p~~Protection ~~s~~Systems as they relate to the reliability of the BES~~Bulk Electric System~~.
- Perform disturbance analysis evaluations.

The selection of particular ~~T~~task~~s~~ for the Reliability Assurer will reflect NERC's judgment on which ~~T~~task~~s~~ merit such a "defense-in-depth" approach.

Section II — Technical Discussions



1. General Clarifications of the Functional Model

The general features of the ~~Functional~~ Model are described in the Introduction, Purpose and Guiding Principles sections of the Model. In brief:

The ~~NERC Reliability Functional Model ("the Model")~~ Model provides the framework for the development and application of NERC's Reliability Standards, as follows:

- *The Model describes a set of Functions that are performed to ensure the reliability of the ~~Bulk Electric System~~BES. Each Function consists of a set of related reliability ~~T~~tasks~~s~~. The Model assigns each Function to a ~~f~~Functional E~~e~~ntity, that is, the entity that performs the Function's ~~T~~tasks. The Model also describes the interrelationships between that ~~f~~Functional E~~e~~ntity and other F~~f~~unctional ~~e~~Entities ~~(that perform other Function).~~*
- *NERC's Standard Development Teams develop Reliability Standards that assign each reliability requirement within a standard to a ~~f~~Functional E~~e~~ntity, as defined in the Model.*
- *This is possible because a given standard requirement will be logically related to a ~~T~~task within a Function. A standards requirement will be very specific whereas a ~~T~~task will be more general in nature.*
- *NERC's compliance processes require specific organizations to register as F~~f~~unctional E~~e~~ntities and comply with standards requirements assigned to the F~~f~~unctional E~~e~~ntities.*
- *The Model's Functions and F~~f~~unctional E~~e~~ntities also provide for consistency and compatibility among different Reliability Standards.*

The ~~NERC Reliability Functional Model ("the Model")~~Model does NOT address:

- *Entity Certification*
- *Registration*
- *Compliance*
- *Sanctions*

There are a number of clarifications that are important for those involved in developing standards and monitoring compliance with them. These clarifications are generally made in the Model itself, but because of their importance and potential for mis-interpretation, they warrant being repeated.

The Model is a guideline, it is not prescriptive. The Model is not a Reliability ~~s~~Standard, and does not have compliance requirements. The Model is a guideline for the development of Reliability ~~s~~Standards and their applicability; it is not a NERC ~~r~~Requirement. Standards developers are not required to include tasks envisioned in the ~~m~~Model, nor are the developers precluded from developing Reliability Standards that conflict with the Model. The Reliability Standards ~~r~~Requirements take precedence over the Model.

A Functional Entity is not an actual organization. The Model describes ~~T~~tasks performed by F~~f~~unctional E~~e~~ntities, which are in effect generic *classes or categories* of organizations — the Model itself does not address *specific* organizations. The Model, for example, describes the Reliability Coordinator, a ~~f~~Functional E~~e~~ntity; the Model does not reference PJM and MISO, which are specific organizations. It is through NERC's registration process that the PJM and MISO organizations become a member of the category of organization called Reliability Coordinator, and thereby responsible for meeting standards requirements specified for the Reliability Coordinator.

Reliability is best served if there is consistency of definitions within all NERC documents. These documents include, but are not limited to, the Functional Model, the NERC Rules of Procedure and Glossary of Terms.

Every Function has an associated ~~f~~Functional E~~e~~ntity. A Function is a set of related reliability ~~T~~tasks; whereas the ~~f~~Functional E~~e~~ntity is the name given to the category of organization that performs these ~~T~~tasks. The diagram (Figure 3) of the Model includes two names within each Function box. The Function is shown in a larger typeface with the associated ~~f~~Functional E~~e~~ntity underneath.

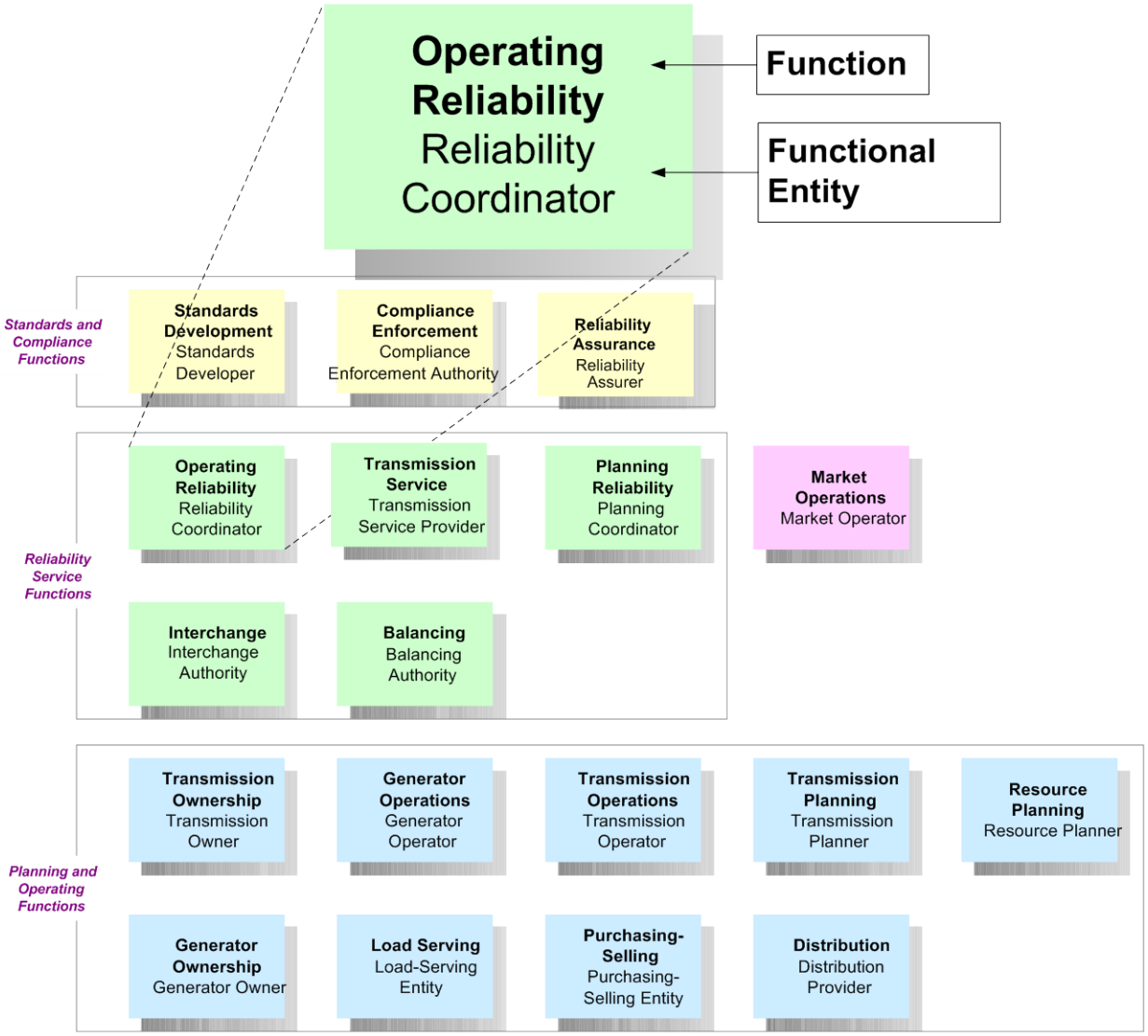


Figure 3 – Function and Functional Entity

Organizations, such as R~~egional~~ T~~ransmission~~ O~~rganization~~s or integrated utilities, may register with NERC as ~~Responsible~~ Functional Entities by identifying which Functions they perform.

For example, as shown in Figure 4 an RTO (organization) may register with NERC to be a Reliability Coordinator, Balancing Authority(ies), and a Transmission Service Provider. In this case we say that the RTO is the **~~Responsible~~ Functional Entity** for the Operating Reliability, Balancing, and Transmission Service Functions. We also use the expression that the RTO has "rolled up" these three Functions and is responsible for ensuring that the ~~T~~tasks~~s~~ within each of those Functions are performed and all applicable standards requirements met.

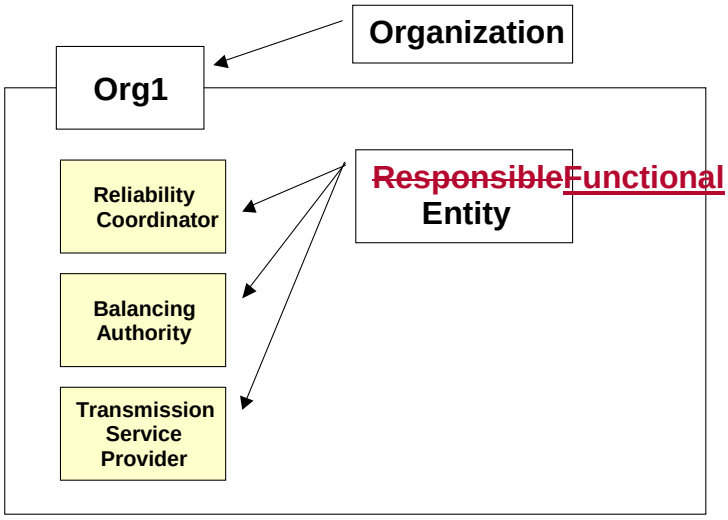


Figure 4 — Organizations may "roll up" more than one ~~f~~Functional ~~e~~Entity.

2. Reliability Standards

The ~~Functional~~ Model describes the Standard Development Function and the Standards Developer Ffunctional Eentity~~-~~ and how these are related to Reliability Standards.

Reliability Standards can be developed at the North American level as well as at the regional level and can therefore be placed in two categories:

1. **Reliability Standards Developed at the North American Level Within NERC**
   NERC, under regulatory authority, develops and maintains Reliability Standards using the NERC Reliability Standards Development Procedures. The Reliability ~~s~~Standards are applicable across North America upon approval by governmental authorities, unless specifically stated otherwise within the standard, and enable NERC and Regional Entities to monitor and enforce compliance with the standards requirements.

   NERC can use the Reliability Standards Development Procedures to approve a variance from a NERC Reliability Standard; the variance then becomes part of the standard. The three categories of variance are:

   - Entity Variance that applies to an area less than a NERC Region
   - Regional Variance that applies to a NERC Region but less than an Interconnection
   - Regional Variance that applies to a NERC Region on an Interconnection-wide basis.

2. **Reliability Standards Developed Within a Regional Entity**
   Regional Entities may develop and propose to NERC ~~r~~Regional ~~r~~Reliability ~~s~~Standards that:

   - Set more stringent reliability requirements than the NERC Reliability Standard
   - Cover matters not covered by an existing NERC Reliability Standard.

   Alternatively, NERC may direct Regional Entities to develop a ~~r~~Regional ~~r~~Reliability ~~s~~Standard in order to implement a NERC Reliability Standard. Such a ~~r~~Regional ~~r~~Reliability ~~s~~Standard, upon approval by NERC, becomes part of the NERC Reliability Standard.

   Regional Entities must use a NERC-approved development process to develop these ~~r~~Regional ~~r~~Reliability ~~s~~Standards. Such ~~r~~Regional ~~r~~Reliability ~~s~~Standards, upon approval by NERC, become NERC Reliability Standards. As appropriate, NERC will approve the ~~r~~Regional ~~r~~Reliability ~~s~~Standard as an:

   - Interconnection-wide ~~r~~Regional Reliability ~~s~~Standard, or
   - Non-Interconnection-wide ~~r~~Regional Reliability ~~s~~Standard.

Regional Criteria. Regional Entities may develop regional reliability criteria that are necessary to implement, to augment or to comply with Reliability Standards, or to address issues not within the scope of Reliability Standards. Such criteria are not approved by NERC and are not (NERC) Reliability Standards. As such, regional criteria, while clearly serving a reliability purpose, are best considered to be outside of the ~~(NERC) Functional~~ Model.

3. Market Operations (Resource Integration)

Market Operations is not a reliability Function. NERC does not assign standards requirements to the Market Operator.

Nevertheless, Market Operations, a commercial or market ~~f~~Function, is included in the ~~Functional~~ Model, in order to provide an interface point between reliability and commercial ~~f~~Functions.

The role of the Market Operator also varies in design and responsibilities, but all Market Operators perform a resource integration task of one form or another under a set of market rules that are recognized by a state, federal, or provincial regulator. Resource integration is discussed further in the following section II- 4, ~~Functional~~ Model and Market Structures.

Versions 4 and 5.1 of the Model refer to the entity as "Market Operator (Resource Integrator)", where Resource Integrator is seen as a better term than Market Operator in areas not having a full-service market. For simplicity, the discussion below uses only the term Market Operator, to apply even where there is not a full-service market.

1. **The Market Operator in a Full-Service Market.**
   A full-service market is one which offers both the commercial services such as integrating resources ahead of Real-time and settlement after the completion of Implemented Interchange and dispatch cycles, and implement the resource plan in Real-time, making adjustment as necessary to meet other reliability requirements not envisaged during the resource integration process (for example, reliability constraints). In a full service market, the Market Operator tasks involve integrating resources in accordance with established market rules. Following its market rules and using available market mechanisms, the Market Operator integrates market resources by establishing a generation dispatch plan to meet the load forecast for the upcoming dispatch cycle (typically five minutes or longer).

   This generation dispatch plan is usually a function of the generators' incremental bids ("merit order"). The established generation dispatch plan is submitted to the Balancing Authority(ies) for implementation. When the plan is tested for implementation, and limitations caused by transmission congestion are identified, the Balancing Authority(ies) will adjust the dispatch schedules accordingly. This constitutes a "security-constrained" dispatch.

Relationship between the Market Operator and Balancing Authority. In a full-service market, there is a close relationship between the Market Operator and the Balancing Authority(ies). A full-service Market Operator performs resource integration task and is assigned the tasks of:

- Determining the generation dispatch plan (unit commitment) ahead of time
- Integrating scheduled interchange into that generation plan

- Designating which generators are available for regulation service
- Providing the generation dispatch plan to the Balancing Authority(ies) ahead of real time.

The Balancing Authority(ies) receives the plan, and implements it in real time.

2. **The Market Operator Where There is not a Full-Service Market.**
   In jurisdictions not having a full-service market there will often be a traditional, vertically-integrated utility that may be both the Market Operator and the Balancing Authority(ies), and most or all of the associated tasks will be performed internal to the utility. The generation dispatch plan will typically be cost-based, in contrast to bid-based dispatch in a full-service market.

   In addition, there are jurisdictions that use a model other than full-service market and vertically-integrated utility, in particular bilateral Interchange Transactions. In this case, the organization serving as Balancing Authority(ies) will also be the Market Operator, operating on the basis of net interchange.

4. The Functional Model and Market Structures

This section explains how the ~~Functiona~~l Model can accommodate different market structures by examining these structures from the perspective of resource integration protocol.

Resource Integration Protocol. A resource integration protocol is the method used to determine the merit order of the generation to be dispatched. Generally, resource integration protocols are either cost-based or bid-based, depending on the market rules established by the regulatory authority, as described in section II-3, Market Operations (Resource Integration). The basis and the results for the resource integration algorithms are generally the same for cost-based and bid-based dispatch, which is why the ~~Functiona~~l Model can accommodate either type of protocol.

Bid-Based Resource Integration. In those areas of the U.S. and Canada having a full-service market, market protocols provide Generator Owners the ability to bid into the market. In those cases, Generator Owners will direct the submission of bids via the Generator Operators to the Market Operator. The market protocols are established by the governmental authority, such as the Federal Energy Regulatory Commission in the U.S. and provincial regulators in Canada. The Market Operator, in turn, provides the Balancing Authority(ies) with the generator dispatch plan, so that the generators within the market footprint would be instructed to operate at the same incremental bid. Transmission constraints may cause the actual dispatch to deviate from the dispatch plan. Redispatch methods used to relieve the congestion may use: direct resource assignments, area / zonal dispatch signals, or bus-signals. The zonal and bus methodologies are often referred to as "Locational Marginal Pricing," or LMP.

Cost-based Resource Integration. Where there is not a full-service market, the Market Operator may be a traditional, vertically-integrated utility that acts also as Balancing Authority(ies). The utility will dispatch its resources based on its incremental costs (fuel and operations and maintenance) and losses. The regulatory authority, such as the state public utility commission, might specify the accounting rules for calculating these costs.

Multiple Balancing Authorities Within a Market Area. If the Market Area includes more than one Balancing Authority(ies) Area, then the Market Operator will also provide each Balancing Authority(ies) with the net "interchange" schedule that results from the resource plan ("Resource Dispatch Interchange Schedule", or RDIS). Each Balancing Authority's RDIS will be an import or export to the Balancing Area, and the sum of all RDISs within the Market Area must add to zero at each dispatch cycle.

The table below describes how the current operating tasks may be performed by both the vertically-integrated utility and the unbundled, full-service market operator.

Task	No Full-Service Market: Vertically Integrated Structure	Full-Service Market: Unbundled Structure
Unit Commitment	Utility (performing as the Generator Owner) decides which units to run.	Generator Owners decides which units to make available.
Economic Dispatch	Utility (as Market Operator or Resource Integrator) performs economic dispatch calculation based on incremental costs or other requirements. Utility must consider generator operating limits, which units are providing regulation service, and any commitments for bilateral arrangements.	Market Operator collects bids from Generator Owners and develops integrated resource plans based on market rules (e.g., bids). Market Operator must consider generator operating limits, which units are providing regulation service, and any commitments for bilateral arrangements.
Congestion Management	Results in different incremental costs ("lambdas").	Depending on the market structure, results in Different locational marginal prices (LMP), or Different marginal costs
Regulation Service	Utility (serving as the Balancing Authority(ies), Load-Serving Entity, and Generator Owner) in concert with the Reliability Coordinator, determines the amount of regulation service required, and designates those units that provide the regulation service. Utility (as Balancing Authority(ies)) uses this information in its economic dispatch.	Balancing Authority(ies), along with Reliability Coordinator, determines the amount of regulation service required. Generator Owners decide which units to bid in for regulation service. Market Operator runs bid pool for regulation service. Load-Serving Entity arranges for regulation services.
Generator Control	Utility (as Balancing Authority(ies)) pulses units that are designated by the Market Operator for regulation service. As regulating ability declines, the part of the utility that acts as Balancing Authority(ies) directs the part of the utility that acts as Market Operator to develop a new dispatch plan.	Balancing Authority(ies) pulses units that are designated by the Market Operator for meeting energy and regulation service requirements. As regulating ability declines, the Balancing Authority(ies) asks the Market Operator for a new dispatch plan.

5. Providing and Deploying Ancillary and Reliability-Related Services

Tariff Domain — Requirement for Ancillary Services. The FERC open access (pro forma) tariff requires the (U.S.) Transmission Provider to provide the following Ancillary Services to all customers taking basic transmission service (Figure 5):

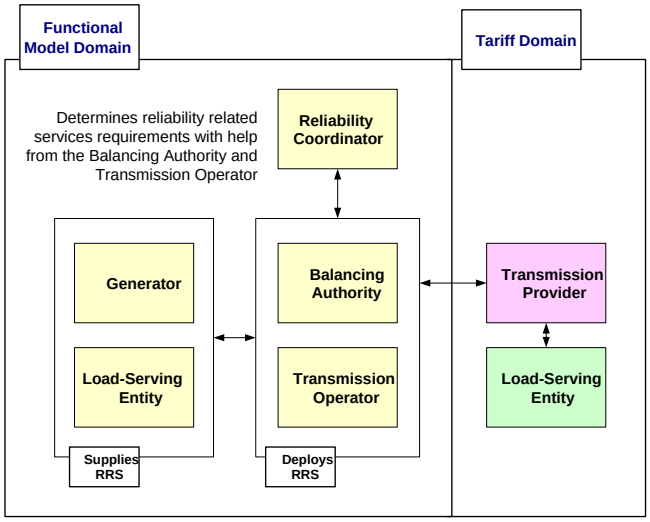


Figure 5 - Supply and Deployment of Ancillary Services and Reliability-Related Services.

Scheduling, system control, and dispatch

1. Reactive supply and voltage control from generation.

The FERC pro-forma tariff requires that the Transmission Provider offer to provide the following services to customers serving loads within the Transmission Provider's own area which do not purchase or self-provide:

2. Energy imbalance
3. Regulation and frequency response
4. Operating reserve — spinning
5. Operating reserve — supplemental.
6. Generator Imbalance

Functional Model Domain — Reliability-related Services. The term "reliability-related services" means those services other than the supply of energy for load that are physically provided by generators, transmitters and loads in order to maintain reliability.

Reliability-related services include voltage control and reactive power resources from generators, transmitters and loads. Certain transmission facilities can provide reactive support, but are not considered an Ancillary Service in the open access tariff, rather, they are considered part of basic

transmission service. In addition, loads may provide reserves through load-shedding or demand-side management, and may also provide frequency response.

Figure 5 shows how Ancillary Services in the “tariff domain” could be served by reliability-related services in the "reliability domain". The ~~Functional~~ Model explains that the Balancing Authority(ies), alone or in coordination with the Reliability Coordinator, determines the amount required and arranges for reliability-related services to ensure balance:

- The Balancing Authority(ies) determines regulation, load following, frequency response, and contingency reserves, etc., and deploys these as reliability-related services.
- The Transmission Operator determines the reliability-related services necessary to meet its reactive power requirements to maintain transmission voltage within operating limits, and deploys these as its set of reliability-related services.
- The Reliability Coordinator, working with the Transmission Operator, determines the need for Black Start capacity. The Transmission Operator cannot do this alone, because it may not have a wide enough picture of the transmission system.

Through its Reliability Standards, NERC holds organizations (those registered as Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Service Providers) responsible to comply with applicable standards requirements, including those requirements that depend on reliability-related services. The quantity of and processes used to deploy those reliability-related services depend on the Regional and local system characteristics and regulatory requirements. The responsible organizations establish the quality and quantity of their own reliability-related services, using these processes and procedures in a manner that ensures compliance with the standards’ requirements.

6. Managing Bilateral Interchange Transactions — Basic Concepts

Interchange that crosses multiple Balancing Authority(ies) (BA) Areas can be broken down daisy-chain fashion into individual Balancing Authority(ies)-to-Balancing Authority(ies) Interchange Transactions, with the Sink Balancing Authority(ies) designated as the "manager" (the "Tag Authority").

The ~~Functional~~ Model recognizes this Interchange process as the current Industry practice and includes BA-to-BA "after hour" checkout for net Interchange between adjacent Balancing Authority(ies). Also, the Interchange ~~Coordinator~~ Authority(ies) ~~f~~Function "coordinates" and "communicates Interchange ("deals") that is ready for physical implementation between Balancing Authorities. The IA~~C~~ receives approvals that recognize ramping capability. The IA~~C~~ also communicates the individual Interchange information to all involved parties (Figure 6).

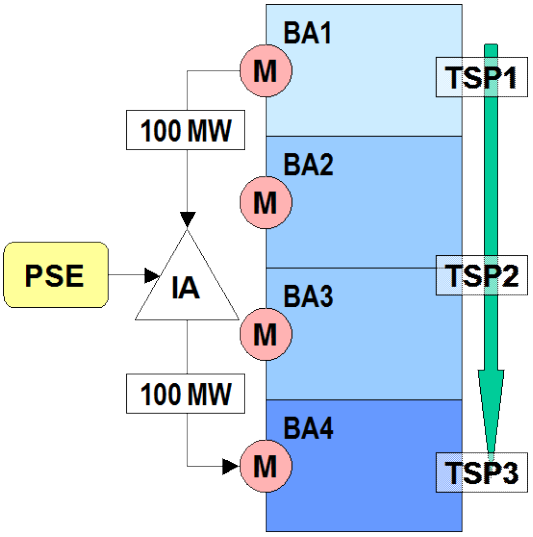


Figure 6 — The Interchange ~~Coordinator~~ Authority(ies) manages transactions between the source and sink Balancing Authority(ies).

Managing Bilateral Interchange Transactions — Allowable Concept

The ~~Functional~~ Model does not prevent Balancing Authorities from scheduling Interchange with Interchange ~~Coordinator~~ Authority(ies) (IA~~C~~). The IA~~C~~s would ensure that the Arranged Interchange is balanced (equal and opposite) between the Source and Sink BAs. In the example in Figure 6, the IA~~C~~ manages a transaction from BA1 to BA4. The schedule is

BA1 → IA → BA4

and the transmission service path is

TSP1 → TSP2 → TSP3.

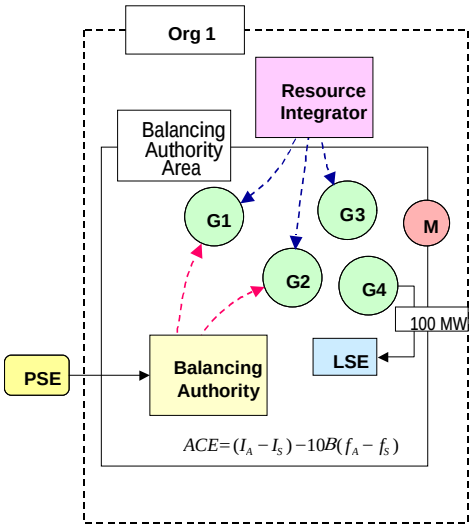


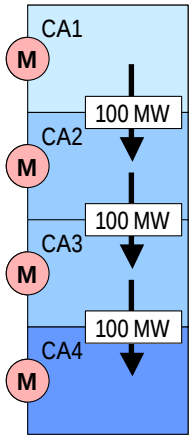
Figure 7 The Purchase-Selling Entity submits the bilateral transaction to the Balancing Authority(ies) intra-BA transactions.

Interchange Transactions within a Balancing Authority(ies) Area. A bilateral Interchange within a Balancing Authority(ies) Area does not require Interchange ~~Coordinator~~ Authority(ies) authorization. In the example in Figures 8 and 9, the Purchasing-Selling Entity submits the 100 MW request for Interchange to the Balancing Authority(ies) who will inform the Resource Integrator (or Market Operator) if the Resource Integrator needs to know which generators are committed to the Interchange, and to the Reliability Coordinator for reliability assessment.

The tables on the following page compare the Interchange checkout procedures that the Balancing Authorities use today with the procedures that the Balancing Authority(ies) would use if this type of Interchange concept were applied.

Checkout under Existing NERC Practice Figure 8			
Control Area	**Actual from Tie Meters**	**Schedule with CA**	**Inadvertent**
CA1	+100 to CA2	+100 to CA2	0
CA2	-100 from CA1 +100 to CA3	-100 from CA1 +100 to CA3	0
CA3	-100 from CA2 +100 to CA4	-100 from CA2 +100 to CA4	0
CA4	-100 from CA3	-100 from CA3	0
Potential Future Checkout Figure 9			
Balancing Authority	**Actual from Tie Meters**	**Schedule with IAC**	**Inadvertent**
BA1	+100 to BA2	+100 to IAC	0
BA2	-100 from BA1 +100 to BA3	0	0
BA3	-100 from BA2 +100 to BA4	0	0
BA4	-100 from BA3	-100 from IAC	0

Figure 8



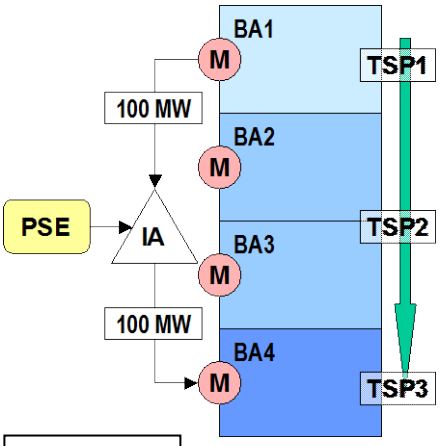


Figure 9

7. Managing Bilateral Interchange — Scheduling EntitiesAgents

Some Transmission Providers provide a Scheduling EntityAgent service for their Balancing Authority(ies) members. The Scheduling Agent Entity provides a single point of contact for all Interchange into or out of those Balancing Authority(ies). For example, the Southwest Power Pool serves as a Scheduling EntityAgent for its members, and any Balancing Authority external to SPP will schedule to any SPP Balancing Authority(ies) by way of the SPP as the Scheduling EntityAgent. This simplifies Interchange scheduling for parties both internal and external to SPP.

In the example in Figure 10, two Interchange Coordinator Authority(ies) arrange a total of 225 MW with the Scheduling EntityAgent for a group of four Balancing Authorities as follows:

IS1 = 100 MW into BA1

IS3 = 50 MW into BA3

IS4 = 75 MW into BA4

IS2 = 0

The Scheduling EntityAgent must ensure that the sum of the Interchange from all Interchange Coordinator Authorities is exactly equal to the sum of the Interchange from the Scheduling EntityAgent to its Balancing Authorities:

ISA1 + ISA2 = IS1 + IS2 + IS3 + IS4

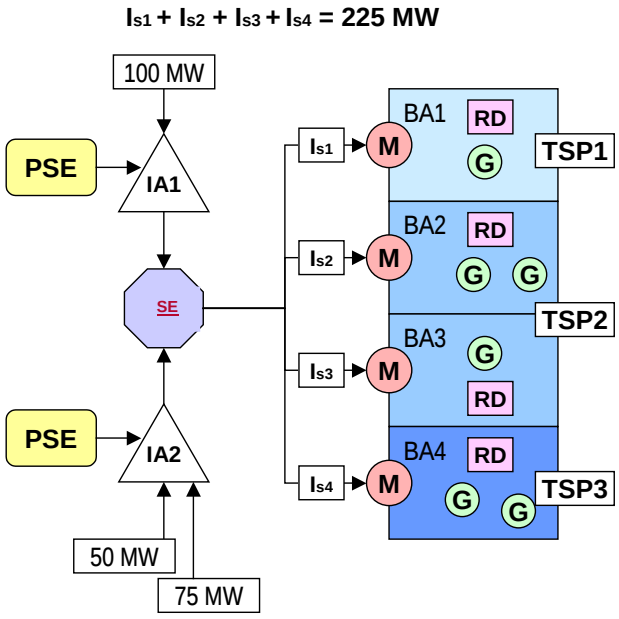


Figure 10 - The Scheduling EntityAgent divides a 100 MW transaction among a group of Balancing Authorities.

If the Balancing Authority(ies) use a Scheduling EntityAgent, then the Interchange Coordinator Authority(ies) will request approvals from the Scheduling EntityAgent — not the Balancing Authority(ies) — during the Interchange authorization process. The Interchange Coordinator Authority(ies) will also notify the Scheduling EntityAgent of any Interchange curtailments.

Because Interchange scheduling is an integral fFunction of the Balancing Authority(ies), the Functional Model Working Group defines that the Scheduling EntityAgent is actuallyas anas an agent of the Balancing Authorities. The Balancing Authorities would still be the Responsible Entities for ensuring that the Interchange from the Scheduling EntityAgent was incorporated into the BAs' energy management systems. Some have argued that the Scheduling EntityAgent would need to be certified and monitored to ensure that it handled the Interchange properly.

8. Non-coincident Resource Integrator and Balancing Authority Areas

Bilaterals between Market Areas. In the examples above, each Balancing Authority(ies) Area was the same as the Market or Resource Integrator Area. When generation is dispatched (either cost-based or bid-based) over several Balancing Authority(ies) Areas, we may be faced with a bilateral Interchange -whose source or sink is the entire Market Area, and cannot be identified with any particular Balancing Authority(ies) within that area. In this situation, the Interchange ~~Coordinator~~ Authority(ies) interfaces with the Scheduling ~~Agent~~ Entity for the Market Area. Then the Scheduling ~~Agent~~Entity, working with the Market Operator will determine how the bilateral Interchange is allocated among the Balancing Authority(ies) Areas.

As was explained in the technical discussion on reliability-related services, the Scheduling ~~Agent~~ Entity ensures that the RDIS are properly allocated to the Balancing Authorities.

Now we can combine the Scheduling ~~Agent's~~ Entity's management of RDIS with bilateral Interchange Transactions as shown in Figure11.

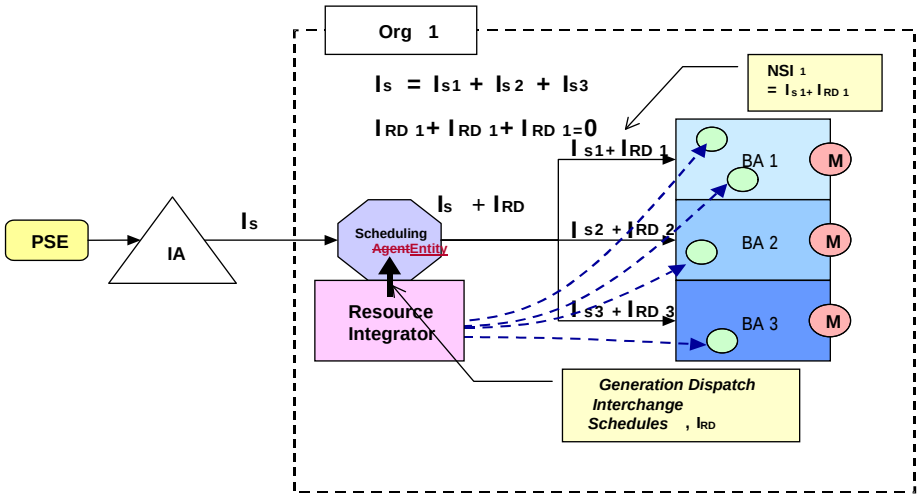


Figure 11 - The Scheduling ~~Agent~~Entity manages bilateral Interchange Transactions in to or out of the Market Area as well as the Interchange Schedules that result from the economic dispatch or market operations.

Bilaterals between Balancing Authorities within the same Market Area. Bilateral Interchange between two Balancing Authorities within the same Market Area does not require Interchange ~~Coordinator~~ Authority(ies) management because the Market Area is under a common tariff, and the Market Operator would have a close relationship with the Reliability Coordinator. In the example in Figure 12 the Purchasing-Selling Entity has submitted a 100 MW request for Interchange from BA1 to BA3 directly to the Scheduling ~~Agent~~Entity, who would

then coordinate the transaction between the source and sink Balancing Authority(ies). The Scheduling ~~Agent~~ Entity then submits the resulting interchange schedule to the Source and Sink Balancing Authorities, and informs the Market Operator if the Market Operator needs to know which generators are committed to the transaction.

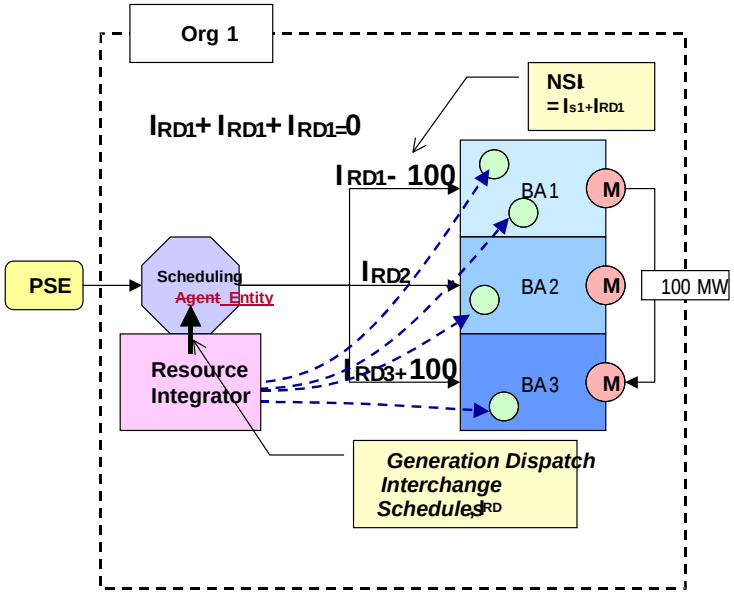


Figure 12 - The PSE submits its Interchange Transaction information directly to the Scheduling Entity~~Agent~~ when the bilateral transaction is within the same Market Area.

9. Implementing the Interchange ~~Coordinator~~ Authority

The IA~~C~~ T~~t~~asks are being performed by the organization registered as BAs, specifically the "~~s~~Sink BA"[2] for a particular interchange transaction. It has been noted that the ~~Functional~~ Model could in principle have assigned the IA~~C~~ T~~t~~asks to the BA and avoided the need for a separate Interchange ~~f~~Function. This approach was not followed because it was envisioned in the future that the IA~~C~~ T~~t~~asks could be performed by entities other than a BA, a possibility that is allowed for by defining the IA~~C~~ separate from the BA. Therefore, the ~~Functional~~ Model *accommodates* the sink BA as the IA~~C~~, but does not *require* it.

The implementation of the IA~~C~~ extends also to the NERC INT standards that exist today, which impose data collecting and interchange-information distribution requirements on an IC.

The NERC direction regarding registering of IA~~C~~s is compatible with the approach taken in the Model:

- There is a need for a separate Interchange ~~Coordinator~~ Authority(ies) F~~f~~unctional E~~e~~ntity.
- Allowance is made for BAs to register as IA~~C~~s, but organizations that are not BAs are not precluded from doing so.
- The IA~~C~~ is an entity, not a software tool.

The remainder of this section clarifies the context and need for an IA~~C~~ from the perspective of the Model, by describing the associated reliability tasks and their implications. As such, it may be of use to those involved in registration processes.

INTERCHANGE PRACTICE

Background

To help ensure reliability, *"requests" for interchange transactions* (Arranged Interchange) must be approved before that request is allowed to become an "implemented" interchange transaction (Confirmed Interchange). Without approvals, it is possible that the sum of all interchange schedules in an interconnection will not sum to zero. That, in turn, would lead to the condition that even if every BA were controlling to zero Area Control Error, there could still be off-generation occurring because of the Net ~~s~~Scheduled Interchange being in error.

Historically, approvals were handled on a control area to control area basis. Net ~~i~~Interchange ~~s~~Schedules between neighbors were checked and approved prior to implementation. Only if there were disagreements did individual requests get checked. This pragmatic practice served the industry well — but not perfectly. When given control areas did not take the time to compute their own Net Scheduled ~~i~~Interchange (and instead merely accepted the numbers from its individual neighbors) — what can and did happen was that individual schedules were active

[2] ~~That is, the BA in whose area the bilateral interchange transaction terminates.~~

on one side of the control area, but not on the other side. Not until serious operational symptoms arose (e.g., unexplained parallel flows, or unusual number of time error corrections) was there an investigation.

Current Practice

The ~~Functional~~ Model's inclusion of an IA~~C~~ recognizes a reliability concern regarding responsibility for approving a request for ~~i~~Interchange, and the distribution of the information for the approved request for ~~i~~Interchange. Each and every transaction that a PSE desires to implement must have approvals from all parties involved, and must have approval by each of them regarding the characteristics of each of those transactions.

Today, the approval and communication are implemented in a two-step process — each step focusing on different quantities. One step focuses on the individual transactions and their respective characteristics. This step is carried out by a tagging authority. The other step focuses on implementing Net Interchange ~~s~~Schedules (i.e., the net of the transactions that were approved). This step is carried out by neighboring BAs. This two-step process can and does work. The problem is that when there is a breakdown in the process, there is no compliance process in place.

For example, if the tagging authority were the root cause of non-compliance (such as a computer error) that caused transaction information to elude analysis of a participant in the transaction, and that error resulted in a blackout, then no one would be held non-compliant, if no entity is registered as IA~~C~~ for the transaction. If a BA_{left} accepts a Net Interchange Schedule from BA_{center} but the transactions within that Net do not agree with the complementary transactions of the accepted Net Interchange Schedule between BA_{center} and BA_{right}, then again no one can be held non-compliant if no one is registered as IA~~C~~.

What is in place today is the NERC Tagging Specification, under which each ~~s~~Sink BA is responsible for providing Tagging Services, either directly or by arranging with a third party to provide this service as its agent.[3] However, the Tagging Specification is not a standard and therefore not a sufficient basis for compliance enforcement.

An important question for many within industry is "how do you implement the concept of an Interchange ~~Coordinator~~ Authority(ies) (IA~~C~~)".

The initial step of the implementation requirements has been met with the NERC Board adoption of the Version 1 Interchange standards, which contain concepts and functions of the IA ~~(now referred to as the IC)~~. The Electronic Tagging Functional Specification assigns the Tag Authority requirements to the entity responsible for Balancing Authority(ies) operations (i.e., Sink BA).

[3]Electronic Tagging Functional Specification, ver 1.8.0, approved Nov 7, 2007, http://reg.tsin.com/Tagging/e-tag/e-tag-spec-v-18-20071107.doc **)**

To implement this concept, the Electronic Tagging Functional Specification (E-tag Spec.) was revised to map the Tagging Service requirement from the Balancing Authority(ies) to the entity performing the Interchange ~~f~~Function for the Sink Balancing Authority's organization (still allows the Sink BA to use third party to fulfill the tasks of the requirements).

10. Distribution Provider as Load-Serving Entity

FERC Order of October 16, 2008[4] approved a NERC filing that proposed, as a short-term solution, revisions to the NERC Statement of Compliance Registry Criteria (Registry Criteria) to provide that a ~~d~~Distribution ~~p~~Provider to whose system the electric loads in retail choice areas are connected will be registered as the LSE for all loads connected to its system.

The Order requires that "the Distribution Provider to whose system the electric loads in retail choice areas are connected are to be registered as the LSE for all loads connected to its system for the purpose of compliance with NERC's approved ~~r~~Reliability ~~s~~Standards applicable to LSEs."

NERC states that, with respect to load served by retail choice through load aggregators, there may not be a clear agreement in place between the ~~d~~Distribution ~~p~~Providers and the load aggregators delineating the responsibilities between the parties regarding compliance with mandatory Reliability Standards. Further, the compliance filing explains that "NERC will exercise its discretion in the application of penalties or sanctions upon Distribution Providers who are providing this information on the behalf of loads served by a retail choice load aggregator until such time as both entities are either registered or the standards are updated to clarify the responsibilities for each party as ultimately i~~n~~dentified in the longer-term solution proposed by NERC."

NERC stated that DPs have both the infrastructure and access to information to enable them to comply with the Reliability Standards that apply to LSEs. Moreover, ~~d~~Distribution ~~p~~Providers provide the wires over which the load of retail power marketers is served. NERC also pointed out that, with regard to ~~d~~Distribution ~~p~~Providers that provide wires service for retail power marketers, these DPs were LSEs for that load prior to state retail access programs. In many instances, these ~~d~~Distribution ~~p~~Providers remain providers of last resort and must plan their system taking into consideration all load served over their wires, including retail access load.

The Order also provides that a ~~d~~Distribution ~~p~~Provider will not be registered based on the above criterion if it has transferred responsibility to another entity (that is appropriately registered) by written agreement.

NERC also stated that this approach ensures that all loads are represented in the planning and operation of the Bulk-Power System by the entity with the best information regarding those loads.

The scope of the review leading to Version 5.1 of the ~~Functional~~ Model included consideration of whether changes should be made in the Model to accommodate these changes to the Registry Criteria.

[4] This section contains extracts from the order, which may be found at http://www.nerc.com/files/Statement_Compliance_Registry_Criteria-V5-0.pdf

Version 5.1 does *not* contain changes to reflect these changes to the Registry Criteria, as follows:

- the problem and its solution relate to registration, not the tasks performed, and as such do not directly affect the Model; this is in keeping with the approach used for the Joint Registration Organization, which is defined for compliance purposes and not in the Model
- the present solution is a short-term one, with the longer-term solution yet to be defined.

- ~~the present solution is a short-term one, with the longer-term solution yet to be defined.~~

11. Terminology Changes in Version 5

Version 5 contains terminology changes intended to improve consistency between the Model and the NERC Glossary, the Rules of Procedure (ROP) and Reliability Standards.[5] Inconsistency has potential for creating needless complexity, confusion and wasted effort for those who use NERC documents. The changes are of three types:

- Entity terminology
- Entity names
- Entity definitions.

Entity terminology

The term "responsible entity" in the Model has been changed to "functional entity".[6]

- The usage of "responsible" in Version 4 derived from an earlier version of the Model. Version 4 clarified that the Model is limited to describing the performance of tasks, but not compliance aspects such as responsibility for such performance. Version 5 takes this clarification one step further by replacing the term "responsible" in the Model.
- The Model uses the term functional entity to apply to a *class of entity*, such as a Balancing Authority, and makes no reference to the *specific organizations* that register as functional entities. Consistency within NERC documents would be improved if conforming changes were made to the NERC Rules of Procedure and Glossary of Terms to consistently use the term "functional entity" when the reference is to the *class of entity* (e.g., BA), and use the terms "responsible entity" and "registered entity" when the reference is to a *specific organization* regarding its responsibility or registration, respectively.[7]

Entity names

- The functional entity name Interchange Authority has been changed to Interchange Coordinator
  - The term "coordinator" better reflects the nature of the function.
  - A conforming change would be required in the Glossary (which also uses Interchange Authority)
- Conforming changes would be required in other NERC documents.

[5] Full alignment will require conforming changes in Reliability Standards, the Glossary and ROP. These changes are seen as editorial that is, not representing changes to essential content.

[6] Version 4 actually uses "Responsible Entity". Because the Glossary and ROP generally use "responsible entity", i.e., all lower case, this usage has been adopted for version 5 of the Model.

[7] These changes in terminology are intended to address confusion between the entity described in the Model and specific organizations, which has been a frequently expressed concern of stakeholders.

Entity definitions

- The Model has been revised to define the various *functional entities*, not the *Functions* as at present, consistent with the approach used in the Glossary and standards.
- The functional entity definitions have been revised.
  - The form of the definitions is uniform, with each definition beginning: "The functional entity …"
  - Each definition is single sentence, limited to a simple statement of the nature of the tasks performed. As a result some of the current descriptive wording in Version 4 or Glossary definitions has been removed in the Version 5 definitions.

The following table gives the Version 4 definitions, the Glossary definitions (April 20, 2009), and the Version 5 definitions (recommended for use in the Glossary.

Functional Entity Definitions:

Model Version 4, NERC Glossary and Model Version 5

VERSION 4[8]	GLOSSARY[9]	VERSION 5[10]	COMMENT
Balancing Authority	**Balancing Authority**	**Balancing Authority**	
Integrates resource plans ahead of time, and maintains load-interchange-generation balance within a Balancing Authority Area and supports Interconnection frequency in real time.	The responsible entity that integrates resource ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.	The functional entity that integrates resource plans ahead of time, maintains generation-load-interchange-balance within a Balancing Authority Area, and contributes to Interconnection frequency in real time.	Minor Glossary change needed.
Compliance Enforcement Authority	**Compliance Monitor**	**Compliance Enforcement Authority**	
Monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-compliance to the standards.	The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.	The functional entity that monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-compliance to the	Glossary needs to be updated

[8] For simplicity of presentation, the definitions indicated for the Model in Version 4 are assigned to the functionFunctional entityFunctional Entity, not the functionFunction. For example, the Model has a definition for the Standards Development functionFunction, but the definition is shown below as applying to the Standards Developer *function**Functional entity**Functional Entity*.

[9] Glossary version of February 12, 2008. See link at http://www.nerc.com/files/Glossary_12Feb08.pdf

[10] These definitions would replace existing definitions in the Glossary (but entities not currently defined in the Glossary would not be added).

VERSION 4[8]	GLOSSARY[9]	VERSION 5[10]	COMMENT
		standards.	
Distribution Provider	**Distribution Provider**	**Distribution Provider**	
Provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer.	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.	The functional entity that provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer.	Glossary change needed – descriptive detail removed. Revised version would be essentially that of Version 4 of the Model.
Generator Operator	**Generator Operator**	**Generator Operator**	
Operates generating unit(s) to provide real and reactive power.	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.	The functional entity that operates generating unit(s) and performs the functions of supplying energy and reliability-related services.	Minor Glossary change needed.
Generator Owner	**Generator Owner**	**Generator Owner**	
Owns and provides for maintenance of generating facilities.	Entity that owns and maintains generating units.	The functional entity that owns and maintains generating units.	Minor Glossary change needed.
Interchange Coordinator	**Interchange Authority**	**Interchange Coordinator**	
Ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates implementation of valid and balanced Arranged Interchange between Balancing Authority Areas.	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.	The functional entity that ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates implementation of valid and balanced Confirmed Interchange between Balancing Authority Areas.	Glossary changed needed. Revised version would be essentially that of Version 4 of the Model.
Load-Serving Entity	**Load-Serving Entity**	**Load-Serving Entity**	
Secures capacity, energy and transmission services (including necessary	Secures energy and transmission service (and related Interconnected	The functional entity that secures energy and transmission services (and	Minor Glossary change needed.

VERSION 4[8]	GLOSSARY[9]	VERSION 5[10]	COMMENT
reliability-related services) to serve the End-use Customer.	Operations Services) to serve the electrical demand and energy requirements of its end-use customers.	reliability-related services) to serve the electrical demand and energy requirements of its end-use customers.	
Market Operator (Resource Integrator)	[not defined]	**Market Operator (Resource Integrator)**	
The Market Operations function, its tasks, and the interrelationships with other entities are included in the Functional Model only as an interface point of reliability Functions with commercial functions.		The market entity whose interrelationships with other entities are included in the Functional Model only as an interface point of reliability functions with commercial functions.	Term not used in Reliability Standards and therefore is not required in the Glossary..
Purchasing-Selling Entity	**Purchasing-Selling Entity**	**Purchasing-Selling Entity**	
Purchases or sells energy, capacity, and necessary reliability-related services as required.	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.	The functional entity that purchases or sells, and takes title to, energy, capacity, and reliability-related services.	Glossary change needed – descriptive detail removed.
Planning Coordinator	**Planning Authority / Coordinator**	**Planning Coordinator**	
Ensures a plan (generally one year and beyond) is available for adequate resources and transmission within a Planning Coordinator area. It integrates and evaluates the plans from the Transmission Planners and Resource Planners within the Planning Coordinator area to ensure those plans meet the Reliability Standards.	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.	The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas	Minor Glossary changed needed.
Reliability Assurer	[not defined]	**Reliability Assurer**	
Monitors and evaluates the activities related to planning		The functional entity that monitors and evaluates the	Term not used in Reliability Standards and therefore is

VERSION 4[9]	GLOSSARY[9]	VERSION 5[10]	COMMENT
and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.		activities related to planning and operations, and coordinates activities of functional entities to secure the reliability of the Bulk Electric System within a Reliability Assurer Area and adjacent areas.	not required in the Glossary.
Reliability Coordinator	**Reliability Coordinator**	**Reliability Coordinator**	
Ensures the real-time operating reliability of the bulk power system within a Reliability Coordinator Area.	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.	The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.	Glossary changed – descriptive detail removed. Revised version would be essentially that of Version 4 of the Model.
Resource Planner	**Resource Planner**	**Resource Planner**	
Develops a plan (generally one year and beyond) within its portion of a Planning Coordinator area for the resource adequacy of its specific loads (End-use Customer demand and energy requirements) within a reliability area.	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy [of] specific loads (customer demand and energy requirements) within a Planning Authority Area.	The functional entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Resource Planner area.	Minor Glossary change needed.
Standards Developer	[not defined]	**Standards Developer**	

VERSION 4[8]	GLOSSARY[9]	VERSION 5[10]	COMMENT
Develops and maintains Reliability Standards to ensure the reliability of the bulk power system.		The functional entity that develops and maintains Reliability Standards to ensure the reliability of the Bulk Electric System.	Term not used in Reliability Standards and therefore is not required in the Glossary.
Transmission Operator	**Transmission Operator**	**Transmission Operator**	
Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.	The functional entity that ensures the Real-time operating reliability of the transmission assets within a Transmission Operator Area.	Glossary changed needed. Revised version would be essentially that of Version 4 of the Model.
Transmission Owner	**Transmission Owner**	**Transmission Owner**	
Owns and provides for the maintenance of transmission facilities.	The entity that owns and maintains transmission facilities.	The functional entity that owns and maintains transmission facilities.	Minor Glossary change needed.
Transmission Planner	**Transmission Planner**	**Transmission Planner**	
Develops a plan (generally one year and beyond) for the reliability of the interconnected bulk power system within the Transmission Planner Area. Ensures that the plan integrates resources and transmission within its area as well as coordinating with the plans from adjacent and overlapping Transmission Planners and Resource Planners. The Transmission Planner also ensures that the plan meets the Reliability Standards.	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.	The functional entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within a Transmission Planner Area.	Minor Glossary change needed.
Transmission Service Provider	**Transmission Service Provider**	**Transmission Service Provider**	
Administers the transmission tariff and provides transmission services under applicable transmission service agreements (for example, the pro forma tariff).	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.	The functional entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.	Minor Glossary change needed.

~~12.~~11.

Reliability Areas and Boundaries

Assets versus Geography as the Basis for Defining Areas and Boundaries

It is useful for organizations that are ~~f~~Functional Ee~~e~~ntities to specify an associated Area, which defines the portion of the ~~Bulk Electric System~~BES within which their ~~f~~Functional ~~e~~Entity status applies. Moreover, by reviewing all of the Areas for a particular ~~f~~Functional ~~e~~Entity, it is possible to establish whether there are overlapping responsibilities or gaps, which can then be eliminated. The concept of Areas and boundaries (the interfaces between adjacent Areas) is therefore important in establishing clear responsibilities for compliance with Reliability Standards.

The ~~Functional~~ Model building block for defining boundaries and Areas for the ~~f~~Functional entities that operate and plan the B~~ulk~~ E~~lectric~~ S~~ystem~~ is electrical, namely the individual B~~ulk~~ E~~lectric~~ S~~ystem~~ asset. That is, the building blocks are the individual transmission, generation and customer equipment assets that collectively constitute the B~~ulk~~ E~~lectric~~ S~~ystem~~. This enables any given B~~ulk~~ E~~lectric~~ S~~ystem~~ asset to be associated with a single organization, with respect to any particular ~~f~~Functional ~~e~~Entity. This will therefore provide the basis for clear assignment of responsibility for managing the potential reliability impacts of the asset, where the specific responsibility is to be established in NERC's registration, certification and compliance processes.

It is noted that a geographic definition is not adequate in a situation where there are, for example, two Transmission Operators in a given geographic footprint, differentiated by the voltage level of the assets under their respective control. In such a situation, the use of the specific ~~Bulk Electric System~~BES assets provides an adequate basis for defining Areas/boundaries.

The NERC Rules of Procedure specify area relationships among ~~f~~Functional Ee~~e~~ntities, excerpted as follows:

> 2.2 Regional entities shall verify that all balancing authorities and transmission operators are under the responsibility of one and only one reliability coordinator.
>
> 2.3 Regional entities shall verify that all transmission elements of the bulk power system operated within their geographic boundaries are under the authority and control of one and only one transmission planner, planning authority, transmission owner, and transmission operator.
>
> 2.4 Regional entities shall verify that all loads and generation sources within their geographic boundaries are under the authority and control of one and only one balancing authority.
>
> 2.5 Regional entities shall verify that no geographical or electrical areas of the bulk power system within their boundaries have duplication of coverage or are lacking an entity to perform required duties and tasks as identified in the ~~r~~Reliability ~~s~~Standards.

Size Considerations Relating to Area

The ~~Functional~~ Model does not specify a minimum or maximum size for a reliability area. From the perspective of the Model, an organization qualifies to be the ~~Responsible~~ Functional Entity for a particular Function by virtue of performing the Function's ~~T~~tasks.

Size is not a consideration in the distinction between local-area versus wide-area reliability. Local-area reliability is the responsibility of the Transmission Operator in the sense of considerations relating to the Transmission Operator's local system or area, regardless of how large that area may be. Similarly, wide-area reliability is the responsibility of the Reliability Coordinator in the sense of considerations relating as well to the systems and areas of neighboring Reliability Coordinators, regardless of how small the Reliability Coordinator's own area may be.

~~13.~~12. Generating versus Transmission Assets

The Model does not attempt to define the boundary between generating and transmission ~~f~~Facilities, in particular regarding facilities such as protective relays and lines that are within or in proximity to a generating plant perimeter. Such boundaries may be defined by NERC, Regional Entities or governmental authorities.

From the perspective of the Model, for a ~~f~~Facility that is determined to be a generating ~~f~~Facility, its owner will be a Generator Owner, and its operator a Generator Operator. Correspondingly, for a ~~f~~Facility that is determined to be a transmission ~~f~~Facility, its owner will be a Transmission Owner, and its operator a Transmission Operator.

It is recognized that an owner may not be the operator of its ~~f~~Facility, as a result of delegating the operating of the ~~f~~Facility to another party through an ~~a~~Agreement, and that in all cases it is NERC's registration process, not the Model that determines assignment as a ~~f~~Functional ~~e~~Entity.

~~14.~~13. Roles in Load Curtailment

This section discusses the roles of the various ~~f~~Functional E~~e~~ntities that may be involved in load ~~c~~Curtailment. These entities include: Reliability Coordinator, Balancing Authority(ies), Transmission Operator, Distribution Provider and Load-Serving Entity.

Types of Load Curtailment

There are two general types of load curtailment — voluntary and non-voluntary.

A. Voluntary Load Curtailment

Voluntary load curtailments are usually arranged ahead of real time under some form of agreements — market price trigger, compensation, etc., or on a totally voluntary basis with or without any compensation. Implementation of voluntary load curtailment is intended to provide a relief to the market price in some established markets, or a relief to system demand to aid the Balancing Authority(ies) in a tight capacity/energy situation, or a relief to loading on a Distribution Provider system.

Voluntary load curtailment based on pricing structure need not be requested since it is governed by pre-arranged agreement and mechanism. Voluntary curtailments that have not been pre-arranged may need to be communicated. Since ~~e~~End-use ~~c~~Customers are involved in the decision-making process and must respond to the request, and the Load-Serving Entity holds the contractual obligation to serve these customers, such requests are usually communicated to the ~~e~~End-use ~~c~~Customers through the Load-Serving Entity as directed by the initiating entities, which include the Balancing Authority(ies) and the Distribution Provider, to address potential capacity/energy shortfall in the Balancing Authority(ies) area or potential overload on the Distribution Provider system.

B. Non-Voluntary Load Curtailment (Shedding)

Non-voluntary load ~~c~~Curtailments are usually implemented in real time to address imminent or existing capacity/energy shortfalls or transmission reliability concerns such as exceedance of an IROL or SOL, or a low voltage problem. Some pre-arrangements may be made ahead of time such as identifying the amount and location of load to be shed, and specific critical loads that may be excluded from curtailment by feeder configuration. However, since implementation is often of urgent nature, a decision process involving the ~~e~~End-use ~~c~~Customers and communication via the Load-Serving Entity is usually bypassed.

Depending on the need to implement this type of curtailment, load is either curtailed automatically (such as in the case of underfrequency or undervoltage load shedding), or a curtailment directive is made by the Reliability Coordinator, Balancing Authority(ies), or Transmission Operator directly to the Distribution Provider for physical implementation (except when this can be accomplished directly by the Transmission Operator). The Distribution Provider may also have a need to curtail load to address overload problems on its system. In this case, the Distribution Provider may implement load shedding directly.

Role of ~~Responsible~~ Functional Entities in Load Curtailment

Reliability Coordinator
The Reliability Coordinator maintains Real-time system reliability, which includes implementing a number of emergency actions which include directing load shedding to preserve system reliability. In addition, the Reliability Coordinator, in collaboration with the Balancing Authority**(ies)** and Transmission Operator, may also participate in invoking public appeals, voltage reductions, demand-side management, and even load shedding if the Balancing Authority**(ies)** cannot achieve resource-demand balance.

When a Reliability Coordinator has a need to direct non-voluntary load curtailment, it issues a directive to the Distribution Provider or the Transmission Operator to implement the curtailment.

Balancing Authority(ies)
When a Balancing Authority(ies) anticipates or experiences a capacity or energy shortfall, it will take actions such as public appeals, demand-side management programs, and load curtailment, as necessary to maintain a resource/demand/interchange balance. As time permits, the Balancing Authority(ies) may seek voluntary load curtailment to reduce demand in its area. In this case, the Balancing Authority(ies) will communicate such a request to the Load-Serving Entity. In the event of an Energy Emergency, the Balancing Authority(ies) may direct non-voluntary load ~~e~~Curtailment by issuing a directive to the Distribution Provider or the Transmission Operator for implementation.

Transmission Operator
The Transmission Operator, in coordination with the Reliability Coordinator, can take actions such as implementing voltage reductions and implement load shedding to mitigate a transmission emergency. When a Transmission Operator sees a need for non-voluntary load curtailment to relieve transmission constraints, such as an actual or expected exceedance of an operating limit, it implements load shedding that is under its control, or directs a Distribution Provider to physically implement the curtailment.

Distribution Provider
The Distribution Provider provides the facilities that could be used to shed load for emergency action. It is that entity that has the capability to physically shed load, but it is generally not responsible for directing load shedding. Loading shedding is generally directed by the Reliability Coordinator, Balancing Authority(ies) and Transmission Operator.

However, the Distribution Provider may itself initiate voluntary and non-voluntary load curtailments for its own reasons, for example to reduce its area's demand or to mitigate overload on its system. When a Distribution Provider sees a need for voluntary load curtailment, it directs the Load-Serving Entity to communicate a request for curtailment to the ~~e~~End-use ~~e~~Customers. When it sees a need to implement non-voluntary load curtailment to address a loading or voltage concern, it implements the curtailment on its own.

Load-Serving Entity
The Load-Serving Entity identifies the loads for voluntary as well as non-voluntary curtailments. For voluntary load shedding, the LSE is responsible for making contractual arrangements with

eEnd-use eCustomers who participate in such a program, and identifying to the Balancing Authorities and Distribution Providers of such arrangements so that these customers, once committed, would be put on curtailment list if and when needed to address potential capacity shortage and/or system constraints.

For voluntary load curtailment that has not been pre-arranged, the Load-Serving Entity may be directed by the Balancing Authority(ies) or Distribution Provider to communicate its curtailment requests to the eEnd-use eCustomers.

For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons. Once identified and necessary contractual arrangements are made, the Distribution Provider (or the Transmission Operator as appropriate) will make reasonable efforts to arrange (feeder) connection arrangement such that these critical loads will not be curtailed by the load shedding facilities until other options have been exhausted.

The Load-Serving Entity is responsible for communicating requests for voluntary curtailment to the appropriate eEnd-use eCustomers, thereby increasing the effectiveness of voluntary load curtailment. In some jurisdictions, it appears that the “wires” entity, i.e., the Distribution Provider, that performs these Ttask. However, from a fFunctional Mmodel viewpoint, it is the Load-Serving Entity fFunction within that Distribution Provider organization that performs this task.

~~15.~~14. History of Revisions

Version 1
Version 1 of the Model was approved in February 2002.

Version 2
Version 2 of the Model[11] was approved Feb. 10, 2004.

Version 2 responded to confusion between a Function and the organization responsibility for its performance, by separately identifying the Responsible Entity associated with each Function. For example, whereas Version 1 used the single term Transmission Operator for both the Function and responsible entity, Version 2 introduced Transmission Operations as the Function (the ~~T~~task), and Transmission Operator as the Responsible Entity for those ~~T~~tasks. Corresponding changes were made for all Functions. This distinction has been maintained in subsequent versions.

The Market Operation Function and Market Operator were added to the Model to provide an interface point with commercial functions.

Version 1 contained only operating Functions. Version 2 introduced three planning Functions (Planning Reliability, Transmission Planning, Resource Planning) and three associated Responsible Entities (: Planning Authority(ies), Transmission Planner and Resource Planner).

Version 3
Version 3 of the Model was approved February 13, 2007.[12] It addressed a number of issues that arose as NERC transitioned to new, mandatory and enforceable ~~r~~Reliability ~~s~~Standards. Several of these issues were outlined in a final report issued by the Functional Model-Reliability Standards Coordination Task Force (FMRSCTF) in March 2005.[13] The FMRSCTF was established to ensure alignment between the Model and the new NERC standards being developed.

The changes introduced in Version 3 included:

- The Reliability Authority(ies) entity name was changed to Reliability Coordinator, for consistency with terminology used in ~~r~~Reliability ~~s~~Standards.
- Changes were made to more clearly define the Transmission Operations ~~T~~tasks and the relationship of the Transmission Operator with the Reliability Coordinator
- Changes were made to the Interchange Authority(ies)~~Coordinator~~ to accommodate the practice of Balancing Authority-to-Balancing Authority interchange scheduling

[11] See ftp://www.nerc.com/pub/sys/all_updl/oc/fmrtg/Functional_Model_Version_2.pdf.
[12] See ftp://www.nerc.com/pub/sys/all_updl/oc/fmrtg/Function_Model_Version3_Board_Approved_13Feb07.pdf.
[13] Final Report of the Functional Model — Reliability Standards Coordination Task Force (**"**FMRSCTF"), approved March 11, 2005. See ftp://www.nerc.com/pub/sys/all_updl/sac/fmrsctf/FMRSC_TF_Report_3-11-05.pdf.

- The Planning Authority(ies) was renamed the Planning Coordinator
- The Regional Reliability Assurance Function and the Regional Reliability Organization Responsible Entity were added.
- It was clarified that "area" of responsibility for a particular Responsible Entity's applied to the collection of ~~Bulk Electric System~~BES assets associated with the entity, that is, that area was defined electrically, not geographically.

Version 4
Version 4 included the following changes from Version 3:

- The names Regional Reliability Assurance / Regional Reliability Organization ~~-~~were changed to Reliability Assurance / Reliability Assurer.

  The name changes reflect the view that reliability assurance could be performed on other than a regional basis. Moreover, the ~~f~~Functional ~~e~~Entity need not be a Regional Entity.

- The names Compliance Monitoring / Compliance Monitor were changed to Compliance Enforcement / Compliance Enforcement Authority.

  The changes were judged to better reflect the strong role of compliance in the ERO regime.

- The wording was changed in a number of instances to ensure that the Model's ~~T~~tasks and relationships between Responsible Entities do not specify prescriptive requirements. Prescriptive requirements are specified in ~~r~~Reliability ~~s~~Standards and NERC processes, not in the Model.

- For example, references in Version 2 that a Responsible Entity "must ensure" or "is required to ensure" were changed in Version 4 to simply "ensures".

- It was clarified that the Generator Owner and Transmission Owner provide for the maintenance of their respective assets.

  This recognizes that the performance of the maintenance may be assigned by the owner to another party, for example, to a Generator Operator or Transmission Operator, respectively.

Version 5
Version 5 introduced the following changes:

Entity name

- Interchange Authority(ies) has been changed to Interchange Coordinator~~-~~. Also incorporated are the terms Arranged and Confirmed Interchange to be consistent with terminology used in the INT standards.

Terminology
The term "responsible entity" in the Model has been changed to "~~f~~Functional ~~e~~Entity".

  - The usage of "responsible" in Version 4 derived from an earlier version of the Model. Version 4 clarified that the Model is limited to describing the performance of task,

but not compliance aspects such as responsibility for such performance. Version 5 takes this clarification one step further by replacing the term "responsible" in the Model.

- The Model uses the term ~~f~~Functional ~~e~~Entity to apply to a *class of entity*, such as a Balancing Authority(ies), and makes no reference to the *specific organizations* that register as ~~f~~Functional ~~e~~Entities.
- Reliability is best served if there is consistency of definitions within all NERC documents. These documents include, but are not limited to, the ~~Functional~~ Model, the NERC Rules of Procedure and Glossary of Terms.

- Entity definitions
- The Model has been revised to define the various *F~~f~~unctional ~~e~~Entities*, not the *~~f~~Functions*, consistent with the approach used in the Glossary and standards.
- The ~~f~~Functional ~~e~~Entity definitions have been revised.
  - The form of the definitions is uniform, with each definition beginning: "The ~~f~~Functional ~~e~~Entity that…"
  - Each definition is single sentence, limited to a simple statement of the nature of the task performed. As a result some of the current descriptive wording in Version 4 or Glossary definitions has been removed in the Version 5 definitions.

Version 5.1

Version 5.1 incorporated the following changes:

Entity name

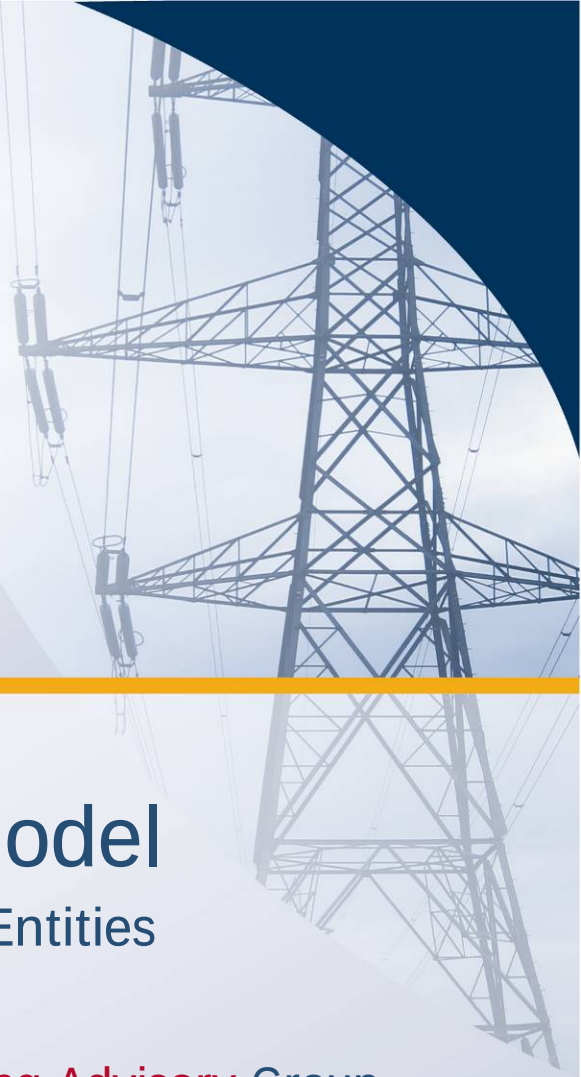
- Interchange Coordinator has been changed to Interchange Authority(ies) to be aligned with NERC Glossary of Terms

Terminology

- The Model has been revised to define the various *Functional Entities*, in alignment with the NERC Glossary of Terms.
- Where appropriate, a term that is capitalized in the NERC Glossary of Terms has been capitalized in the Model and Technical Document

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



Reliability Functional Model

Function Definitions and Functional Entities

Version 5.1

Prepared by the Functional Model ~~Working~~ Advisory Group

~~Approved~~ Endorsed by Standing Committees: ~~December 2009~~
~~Approved~~ Endorsed by Standards Committee: ~~January 2010~~
~~Approved by Board of Trustees: May 2010~~

to ensure the reliability of the bulk power system

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Table of Contents

NERC Reliability Functional Model 1
Table of Contents 2
Revision Summary 4
Foreword 6
Introduction 8
Functional Model Diagram 10
Purpose of the Functional Model 11
Guiding Principles of the Functional Model 13
Functional Model – Clarification Service 15
Functions and Functional Entities 16
Function – Standards Development 17
Functional Entity – Standards Developer 17
Function – Compliance Enforcement 19
Functional Entity – Compliance Enforcement Authority 20
Function – Reliability Assurance 21
Functional Entity – Reliability Assurer 22
Function – Planning Reliability 23
Functional Entity – Planning Coordinator 24
Function – Transmission Planning 26
Functional Entity – Transmission Planner 27
Function – Resource Planning 29
Functional Entity – Resource Planner 30
Function – Reliability Operations 31
Functional Entity – Reliability Coordinator 32
Function – Balancing 35
Functional Entity – Balancing Authority 36
Function – Market Operations 38
Functional Entity – Market Operator (Resource Integrator) 39
Function – Transmission Operations 40
Functional Entity – Transmission Operator 41
Function – Interchange 43
Functional Entity – Interchange ~~Coordinator~~Authority 44
Function – Transmission Service 46

Functional Entity – Transmission Service Provider 47
Function – Transmission Ownership 48
Functional Entity – Transmission Owner 49
Function – Distribution 50
Functional Entity – Distribution Provider 51
Function – Generator Operation 52
Functional Entity – Generator Operator 53
Function – Generator Ownership 54
Functional Entity – Generator Owner 55
Function – Purchasing-Selling 56
Functional Entity – Purchasing-Selling Entity 57
Function – Load-Serving 58
Functional Entity – Load-Serving Entity 59

Revision Summary

The Version 5.1 is an update of the Reliability Functional Model ("the Model" or "Functional Model") that includes the following changes from Version 45:

- ~~Performed detailed analysis on the Planning functions (Planning Reliability, Transmission Planning and Resource Planning) and entities (Planning Coordinator, Transmission Planner and Resource Planner). Clarifying revisions were made to these entities, in particular with respect to the Resource Planning function.~~
- ~~Interchange Authority has been changed to Interchange Coordinator. This version also incorporated the terms Arranged and Confirmed Interchange to be consistent with terminology used in the INT standards.~~
- Terminology
- ~~Clarified asset ownership and maintenance for Generator Owner/Operator and Transmission Owner/Operator.~~
- Errata changes made as necessary.

Terminology Changes

Version 5.1 contains terminology changes intended to improve consistency between the Model and the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary" or "Glossary")~~NERC Glossary~~, the Rules of Procedure (ROP) and Reliability Standards. Inconsistency has potential for creating needless complexity, confusion and wasted effort for those who use NERC documents. The changes are of two~~hree~~ types:

- The terms and definitions in this version of the Functional Model have been aligned with the Glossary[1].
- The Model has been revised regarding terms that are capitalized in the Glossary[2].
- ~~Functional Entity terminology~~
- ~~Entity names~~
- ~~Functional Entity definitions~~

~~Entity terminology~~

~~The Model has been revised regarding terms that are capitalized in the Glossary. In some situations a term was not capitalized per the Glossary. A footnote has been added to give the~~

[1] A table giving current definitions in the Model and Glossary and the proposed definitions is given in the Technical Document.

[2] Unless otherwise indicated, all capitalized terms shall have the meaning set forth in the Glossary or in the Model. In several places in this document, certain Glossary-defined terms are not capitalized as they are intended to have their ordinary meanings (e.g., load) or are intended to match the capitalization of terms within Glossary definitions.

rationale for keeping the term lower case.The term "responsible entity" in the Model has been changed to "functional entity". 3

- The usage of "responsible" in Version 4 derives from an earlier version of the Model. Version 4 clarified that the Model is limited to describing the performance of tasks, but not compliance aspects such as responsibility for such performance. Version 5 takes this clarification one step further by replacing the term "responsible" with "functional" in the Model.
- The Model uses the term functional entity to apply to a *class of entity*, such as a Balancing Authority, and makes no reference to the *specific organizations* that register as functional entities. Consistency within NERC documents would be improved if conforming changes were made to the ROP and Glossary to consistently use the term "functional entity" when the reference is to the *class of entity* (e.g., BA), and use the terms "responsible entity" and "registered entity" when the reference is to a *specific organization* regarding its responsibility or registration, respectively.[4]
-

Entity names

- The functional entity name Interchange Authority has been changed to Interchange Coordinator
  - The term "coordinator" better reflects the nature of the entity.
  - A conforming change is required in the Glossary
  - Conforming changes are required in other NERC documents.

Functional Entity Names have been revised to the same wording as in the Glossary.

Functional Entity definitions

- The Model has been revised to define the various *functional entities*, not the *functions*, consistent with the approach used in the Glossary and standards.
- The Ffunctional Eentity definitions have been aligned to the same wording as in the Glossaryrevised[5].
  - The form of the definitions is uniform, with each definition beginning: "The functional entity that…".
  - Each definition is single sentence, limited to a simple statement of the nature of the tasks performed. As a result some of the current descriptive wording in Version 4 or Glossary definitions has been removed in the Version 5 definitions.

[3] Version 4 actually uses "Responsible Entity". Because the Glossary and ROP generally use "responsible entity", i.e., all lower case, this usage has been adopted for version 5 of the Model.
[4] These changes in terminology are intended to address confusion between the entity described in the Model and specific organizations, which has been a frequently expressed concern of stakeholders.
[5] A table giving current definitions in the Model and Glossary and the proposed definitions is given in the Technical Document.

Foreword

This document replaces version 54 of the NERC Reliability Functional Model that the NERC Board of Trustees Standing Committees approved in May 2010September 20098.

Historically, Control Areas were established by vertically integrated utilities to operate their individual power systems in a secure and reliable manner and provide for their customers' electricity needs. The traditional Control Area operator balanced its load with its generation, implemented Interchange Schedules with other Control Areas, and ensured transmission reliability.

As utilities began to provide transmission service to other entities, the Control Area also began to perform the Ffunction of Transmission Service Provider Transmission Service through tariffs or other arrangements. NERC's Operating Policies reflected this traditional electric utility industry structure, and ascribed virtually every reliability Ffunction to the Control Area.

Beginning in the early 1990s with the advent of open transmission access and restructuring of the electric utility industry to facilitate the operation of wholesale power markets, the functions performed by Control Areas began to change to reflect the newly emerging industry structure. These changes occurred because:

1. Some utilities were separating their transmission from their merchant functions (functional unbundling), and even selling off their generation,
2. Some states and provinces were instituting "customer choice" options for selecting energy providers, and
3. The developing power markets were requiring wide-area transmission reliability assessment and dispatch solutions, which were beyond the capability of many Control Areas to perform.

As a result, the NERC Operating Policies in place at that time, which centered on Control Area operations, were beginning to lose their focus, and become more difficult to apply and enforce.

The NERC Operating Committee formed the Control Area Criteria Task Force (CACTF) in 1999 to address this problem. The task force CACTF began by listing all the tasks required for maintaining electric system reliability and then organizing these tasks into basic groups that it called "functions." Ultimately, the Task Force CACTF decided to build a "Functional Model". This involved breaking down the previous reliability functions more finely, such that all organizations involved in ensuring reliability — whether they are traditional, vertically integrated control areas, regional transmission organizations, independent system operators, independent transmission companies or so on — can identify those functions they perform, and register with NERC as one or more of the fFunctional eEntities. Initially the Model dealt with operating functions, but it was subsequently expanded in Vversion 2 to incorporate planning-related functions. This Functional Model framework provides guidance to NERC standards

drafting teams to write reliability standards in terms of the functional entities who perform the reliability functions.

Adapted from Version 2 of the NERC Functional Model, February 10, 2004

Introduction

The NERC Reliability Functional Model provides the framework for the development and applicability of NERC's Reliability Standards as follows:

- The Model describes a set of ~~Functions~~ tasks that are performed to ensure the reliability of the Bulk Electric System. Each Function consists of a set of related reliability ~~T~~tasks. The Model assigns each Function to a F~~f~~unctional E~~e~~ntity, that is, the entity that performs the F~~f~~unction. The Model also describes the interrelationships between that ~~f~~Functional E~~e~~ntity and other functional entities (that perform other Functions).
- NERC's Standards Development Teams develop Reliability Standards that assign each reliability requirement within a standard to a F~~f~~unctional E~~e~~ntity (that is defined in the Model and NERC's Glossary). This is possible because a given standard requirement will typically be related to a ~~T~~task within a Function. A standard requirement will be very specific, whereas a ~~T~~task in the Model will be more general in nature.
- NERC's compliance processes require specific organizations to register as the entities responsible for complying with standards requirements assigned to the applicable entities.
- The Model's Functions and functional entities also provide for consistency and compatibility among different Reliability Standards.

The Model is a guideline for the development of standards and their applicability. The Model ~~it~~ is not a Standard and does not have compliance requirements. Standards developers are not required to include all tasks envisioned in the model, nor are the developers precluded from developing Reliability Standards that address functions not described in the model. Where conflicts or inconsistency exist, the Reliability Standards requirements take precedence over the Model.

The Model is independent of any particular organization or market structure.

An organization may perform more than one Function.

The Functional Model describes a F~~f~~unctional E~~e~~ntity envisioned to ensure that all of the ~~T~~tasks related to its Function are performed. The Model, while using the term "F~~f~~unctional E~~e~~ntity", is a guideline and cannot prescribe responsibility. It is NERC's compliance processes, backed by regulatory authority, that specify the manner in which, a F~~f~~unctional E~~e~~ntity is "legally responsible" for meeting the standards requirements assigned to that F~~f~~unctional E~~e~~ntity.

The work performed to meet the requirements may be self-~~-~~performed or performed by others.

Functional Model maintenance. The Functional Model is maintained by the Functional Model ~~Working~~ Advisory Group (~~FMWG~~FMAG) under the direction of the NERC Standards Committee, with technical content in the Model and accompanying technical document approved by the Standing Committees (OC, PC and CIPC)

Technical discussions. The companion document, "Functional Model – Technical Discussions," provides additional details on the Functions themselves, how organizations can "roll up" those Functions they wish to perform, and how organizations as "functional entities" interrelate.

The following terms are used in the Functional Model and do not appear in the NERC Glossary.

Functional Entity. The term used in the Functional Model which applies to a class of entity that carries out the ~~T~~tasks within a Function.



Function. A set of related reliability ~~T~~tasks.

~~Task. One of the elements that make up a Function in the Functional Model.~~

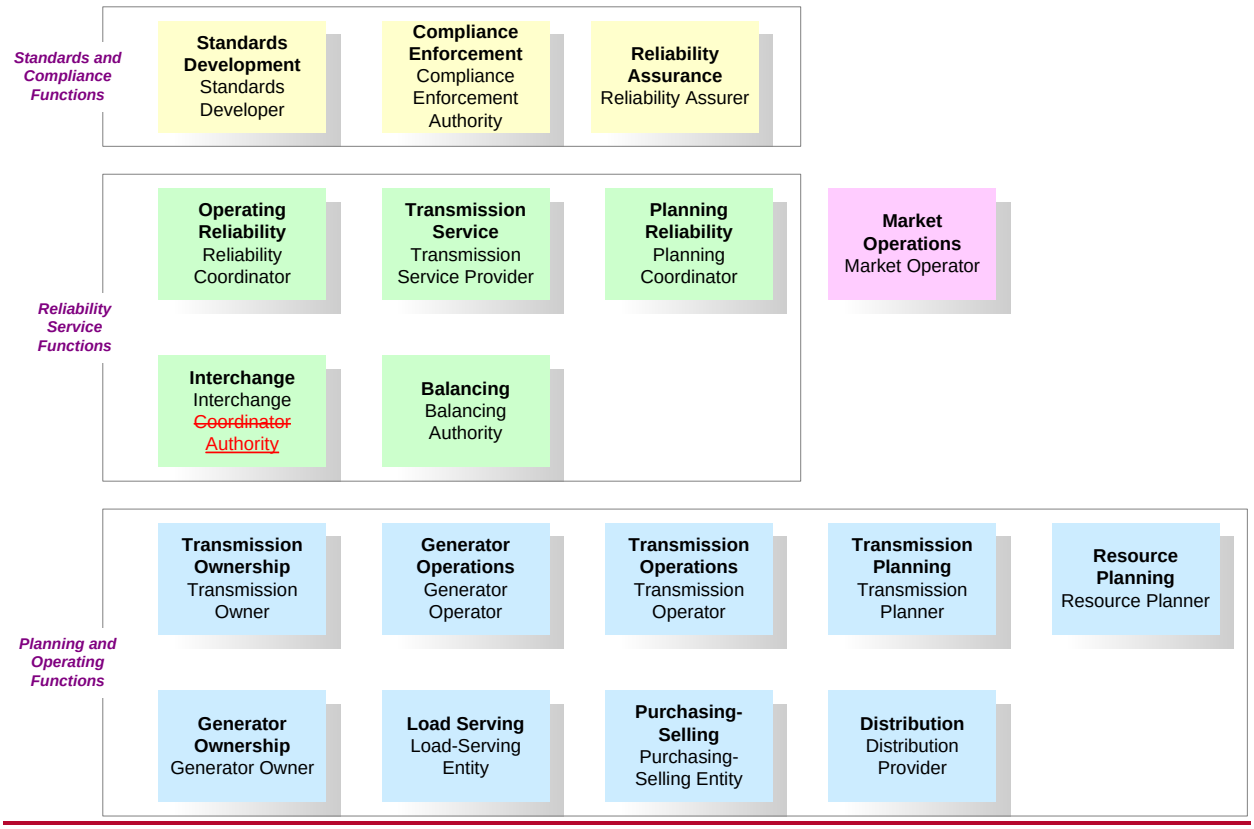
~~**Customer**. The term applies to a customer for transmission, capacity or energy services (a Purchasing-Selling Entity, Generator Owner, Load-Serving Entity, or End-use Customer).~~



End-use Customer. The party served by a Load-Serving Entity (energy) and Distribution Provider (wire service).

Functional Model Diagram

Function Name	***Functional Entity***
Balancing	Balancing Authority
Compliance Enforcement	Compliance Enforcement Authority
Distribution	Distribution Provider
Generator Operations	Generator Operator
Generator Ownership	Generator Owner
Interchange	Interchange ~~Coordinato~~Authorityr
Load-Serving	Load-Serving Entity
Market Operations	Market Operator (Resource Integrator)
Operating Reliability	Reliability Coordinator
Planning Reliability	Planning Coordinator
Purchasing-Selling	Purchasing-Selling Entity
Reliability Assurance	Reliability Assurer
Resource Planning	Resource Planner
Standards Development	Standards Developer
Transmission Operations	Transmission Operator
Transmission Ownership	Transmission Owner
Transmission Planning	Transmission Planner
Transmission Service	Transmission Service Provider


Standards and Compliance Functions
Standards Development
Standards Developer
Compliance Enforcement
Compliance Enforcement Authority
Reliability Assurance
Reliability Assurer
Reliability Service Functions
Operating Reliability
Reliability Coordinator
Transmission Service
Transmission Service Provider
Planning Reliability
Planning Coordinator
Market Operations
Market Operator
Interchange
Interchange Coordinator Authority
Balancing
Balancing Authority
Planning and Operating Functions
Transmission Ownership
Transmission Owner
Generator Operations
Generator Operator
Transmission Operations
Transmission Operator
Transmission Planning
Transmission Planner
Resource Planning
Resource Planner
Generator Ownership
Generator Owner
Load Serving
Load-Serving Entity
Purchasing-Selling
Purchasing-Selling Entity
Distribution
Distribution Provider

Purpose of the Functional Model

The purpose of the NERC Reliability Functional Model is to:

1. Provide a framework for Reliability Standards developed through the NERC standards development process that will apply to certain ~~T~~tasks defined in the Functional Model.
2. Describe in general terms each Function and the relationships between the entities that are responsible for performing the ~~T~~tasks within the Functions. The framework for developing the Function definitions is:
    a. The Functions are independent of the organization structure performing the functions, and
    b. The Functions provide flexibility to accommodate the range of presently conceivable organization structures, as well as accommodate alternative tools, procedures and processes.

Guiding Principles of the Functional Model

As explained in the Introduction, the Model provides the framework on which the NERC Reliability Standards are developed and applied. To ensure that this framework remains viable, the Model itself is governed by a set of "guiding principles" that define a Function's ~~T~~tasks and establish the relationships between the functional entities which are responsible for meeting the requirements in the NERC Reliability Standards that correspond to these ~~T~~tasks. These principles serve as a guideline to those revising or interpreting the Model.

For further details, refer to the Technical Discussions section in the Functional Model Technical Document.

1. The Model must be *complete*, that is, it must include all reliability ~~T~~tasks and interrelationships between entities performing them. This helps ensure that any reliability requirement arising in a Reliability Standard will generally be related to a ~~T~~task in the Model and therefore be assignable to a particular F~~f~~unctional E~~e~~ntity.
2. The Model must group these ~~T~~tasks into a set of Functions, such that:
   - There are enough Functions (and corresponding functional entities) to accommodate the full range of organization structures and responsibilities within the industry, and
   - The number of Functions is developed based on logical grouping of the ~~T~~tasks and kept low as reasonably possible.
     - In particular, where a number of organizations that perform a given Function form a single group, the Model recognizes this as a business arrangement among organizations, not a new Function and corresponding new F~~f~~unctional E~~e~~ntity. That is, the fundamental reliability ~~T~~tasks, and hence the Function, remain the same - all that has changed is *how* the Function is performed. ~~Examples of such groups are a rReserve sSharing gGroup (a collection of entities that are Balancing Authorities), or a planned resource sharing group.~~
3. The Model is structured to ensure there are no gaps or overlaps in the performance of operation ~~T~~tasks in the operating timeframe anywhere in the Bulk Electric System. This is achieved in part by associating an "area" of purview for each F~~f~~unctional E~~e~~ntity. Areas are defined in term of the individual transmission, generator and customer equipment assets that collectively constitute the Bulk Electric System. For example, each Bulk Electric System asset has one Reliability Coordinator, one Balancing Authority, and one Transmission Operator. Regarding overlaps for planning, as described in the Technical Document, it is not always possible to achieve this in the case of planning Functions, where there may be overlapping levels of responsibility for given assets. Questions regarding relationships between the areas of different functional entities, such as whether one type of area must be totally within another type of area, will be defined in Reliability Standards or the Rules of Procedure, not the Model.
4. Tasks describe *what* is to be done, not *how* it is to be done.
5. The Model is a guideline that describes reliability ~~T~~tasks and interrelationships between the entities that perform them - it is not prescriptive. In particular, the Model does not

address requirements for registering or becoming certified as a Ff~~f~~unctional Ee~~e~~ntity, or the delegation or splitting of responsibility for meeting standards requirements.

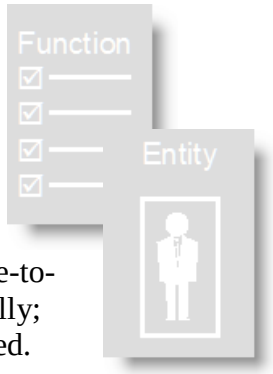
Functional Model — Clarification Service

The Functional Model is a reference tool that links ~~f~~Functional ~~e~~Entities with associated reliability-related functions and respective ~~T~~tasks. Drafting teams use the Functional Model to help them determine which F~~f~~unctional E~~e~~ntity should be required to comply with each requirement in a ~~r~~Reliability ~~s~~Standard.

From time to time questions of clarification and interpretation arise. The FMA~~W~~G is following the process described below for handling requests for clarification of the Functional Model. This process, which has been approved by the Standards Committee, is accessible to all drafting teams as well as any other interested stakeholders. If a drafting team needs help in understanding ~~T~~tasks that make up a Function and/or in determining which functional entities should be responsible for particular standards requirements, the drafting team's coordinator will send an e-mail to the NERC Staff assigned as the FMA~~W~~G facilitator with a request for clarification.

1. The NERC Staff assigned as the FMA~~W~~G facilitator will convene a conference call/meeting of available members of the FMA~~W~~G to review the question(s) and provide a clarification.
   - If the question(s) need more detailed discussion with the drafting team, the two coordinators will organize a conference call/meeting with available members of the FMA~~W~~G and available members of the drafting team to discuss the issues in more detail.
2. Each FMA~~W~~G request for clarification and the associated response will be posted on the NERC Functional Model Web Page under a Frequently Asked Questions section.
   - If the questions result in changes to the model, the changes will be added to a change summary table used to develop the next updated version of the Functional Model document.

Functions and Functional Entities



This section defines the functions and associated ~~T~~tasks that are necessary to plan and operate the Bulk Electric System in a reliable manner. This section also characterizes the functional entities that perform these ~~T~~tasks, and provides examples of the inter-relationships that take place between entities to ensure reliability. As standards are developed, the Model may be revised to add and remove ~~T~~tasks under specific Functions to aid in the development of standards. Relationships between functional entities in the Model are reciprocal. Where a one-to-one relationship exists, the Model will include the reciprocal relationship specifically; and where a one-to-many relationship exists, the reciprocal relationships are implied.

Function — Standards Development

Tasks

1. Develop and maintain a standards development process.
2. Develop Reliability Standards for the planning and operation of the Bulk Electric System.



Functional Entity — Standards Developer



Definition
The ~~f~~Functional ~~e~~Entity that develops and maintains Reliability Standards to ensure the reliability of the Bulk Electric System.

Introduction to the Standards Developer
The Model addresses Reliability Standards created at NERC using the NERC Standard Processes Manual~~NERC Reliability Standards Development Procedure~~ and Regional Reliability Standards~~Regional Standards~~ that are created through an open Regional process and approved by NERC for enforcement. The Functional Model is intended to serve as the framework for the development and application of these Reliability Standards.

Relationships with Other Functional Entities

1. Receives request for Reliability Standards through the public process.
2. Sends Reliability Standards to the Compliance Enforcement Authority.

Function — Compliance Enforcement



Tasks

1. Develop, maintain and implement a compliance enforcement process.
2. Evaluate and document compliance.

Functional Entity — Compliance Enforcement Authority

Definition

NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards~~The functional entity that monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-compliance to the standards~~.

Relationships with Other Functional Entities

1. Receives Reliability Standards from the Standards Developer.
2. Administers the compliance enforcement process for all functional entities as required by Reliability Standards.



Function — Reliability Assurance

Tasks



1. Coordinate reliability assurance among adjacent Reliability Assurers through the development of necessary protocols and processes.
2. Coordinate the activities related to maintaining critical infrastructure protection.
3. Establish reliability assurance processes and documentation related to planning and operations within the Reliability Assurer's area including such things as a regional reliability plan or a Reliability Coordinator plan.
4. Identify and address gaps in reliability processes and responsibilities.

Functional Entity — Reliability Assurer

Definition

The ~~f~~Functional ~~e~~Entity that monitors and evaluates the activities related to planning and operations, and coordinates activities of functional entities to secure the reliability of the Bulk Electric System within a Reliability Assurer area and adjacent areas.



Relationships with Other Functional Entities

1. Coordinates reliability assurance activities of the F~~f~~unctional E~~e~~ntities within the Reliability Assurer area.
2. Coordinates reliability assurance activities with adjacent Reliability Assurers.
3. Coordinates critical infrastructure protection programs with F~~f~~unctional E~~e~~ntities.
4. Collects information from ~~f~~Functional ~~e~~Entities related to Reliability Assurance processes.

Function — Planning Reliability



Tasks

1. Develop and maintain methodologies for the analysis and simulation of the transmission systems in the evaluation and development of transmission expansion plans and the analysis and development of resource adequacy plans.
2. Define information required for planning purposes, and facilitate the process for consolidating and collecting or developing such information, including:
    a. Transmission facility characteristics and ratings.
    b. Demand and energy forecasts, capacity resources, and demand response programs.
    c. Generator unit performance characteristics and capabilities.
    d. Long-term capacity purchases and sales.
3. Evaluate, develop, document, and report on resource and transmission expansion plans for the Planning Coordinator area. Integrate the respective plans, evaluate the impact of those plans on and by adjoining Planning Coordinator's integrated plans and assess whether the integrated plan meets reliability needs, and, if not, then to report on potential transmission system and resource adequacy deficiencies and suggest or facilitate the process for developing alternative plans to mitigate identified deficiencies.
    a. Evaluate the plans that are in response to long-term (generally one year and beyond) customer requests for transmission service.
    b. Review transmission facility plans required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.
    c. Review and determine transfer capability (generally one year and beyond) as appropriate.
    d. Monitor and evaluate transmission expansion plan and resource plan implementation.
    e. Coordinate projects requiring transmission outages that can impact reliability and firm transactions.
4. Coordinate with adjoining Planning Coordinators so that system models and resource and transmission expansion plans take into account modifications made to adjacent Planning Coordinator areas.
5. Develop and maintain transmission and resource (demand and capacity) system models to evaluate transmission system performance and resource adequacy.

Functional Entity — Planning Coordinator

Definition

The responsible entity that coordinates and integrates transmission ~~facility~~ Facilities and service plans, resource plans, and Protection Systems.[6] ~~The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.~~

Introduction to the Planning Coordinator

The Planning Coordinator is responsible for assessing the longer-term reliability of its Planning Coordinator area. While the area under the purview of a Planning Coordinator may include as few as one Transmission Planner and one Resource Planner, the Planning Coordinator's scope of activities may include extended coordination with integrated Planning Coordinators' plans for adjoining areas beyond individual system plans. By its very nature, Bulk Electric System planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one S~~s~~ystem does can affect the other ~~s~~Systems. Planning Coordinators work through a variety of mechanisms to conduct facilitated, coordinated, joint, centralized, or regional planning activities to the extent that all network areas with little or no ties to others' areas, such as interconnections, are completely coordinated for planning activities.



Relationships with Other Functional Entities

1. Coordinates and collects data for system modeling from Transmission Planner, Resource Planner, and other Planning Coordinators.
2. Coordinates transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators.
3. Coordinates plans with Reliability Coordinator and other Planning Coordinators on reliability issues.
4. Receives plans from Transmission Planners and Resource Planners.
5. Collects information including:
    a. Transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.
    b. Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners.
    c. Generator unit performance characteristics and capabilities from Generator Owners.
    d. Long-term capacity purchases and sales from Transmission Service Providers.

[6] In the NERC Glossary, Planning Coordinator and Planning Authority are defined interchangeably.

6. Collects and reviews reports on ~~t~~Transmission and resource plan implementation from Resource Planners and Transmission Planners.
7. Submits and coordinates the plans for the interconnection of facilities to the Bulk Electric System within its Planning Coordinator area with Transmission Planners and Resource Planners and adjacent Planning Coordinator areas, as appropriate.
8. Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the ~~transmission~~ S~~s~~ystem.
9. Facilitates the integration of the respective plans of the Resource Planners and Transmission Planners within the Planning Coordinator area.
    a. Reviews the integrated plan with respect to established reliability needs considering the impact on and by adjoining ~~s~~Systems.
    b. In coordination with the Resource Planners and Transmission Planners, facilitates the development of alternative solutions for plans that do not meet those reliability needs.

Function — Transmission Planning

Tasks

1. Maintain and develop, in cooperation with adjacent and overlapping Transmission Planners, methodologies and tools for the analysis and simulation of the ~~t~~Transmission systems in the evaluation and development of ~~t~~Transmission expansion plans related to resource ~~a~~Adequacy plans.
2. Define, consolidate and collect or develop, in cooperation with adjacent and overlapping Transmission Planners, information required for planning purposes including:
   a. Transmission facility characteristics and ~~r~~Ratings.
   b. Demand and Electrical ~~e~~Energy forecasts, capacity resources, and ~~d~~Demand-Side Management ~~response~~ programs.
   c. Generator unit performance characteristics and capabilities.
   d. Long-term capacity purchases and sales
3. Maintain transmission system models (steady state, dynamics, and short circuit) to evaluate Bulk Electric System performance.
4. Coordinate with adjacent and overlapping Transmission Planners so that system models and resource and ~~t~~Transmission expansion plans take into account modifications made to adjacent and overlapping Transmission Planner areas.
5. Evaluate, develop, document, and report on expansion plans for the Transmission Planner area. Assess whether the integrated plan meets reliability needs, and, if not, report on potential network conditions or configurations that do not meet performance requirements and provide potential alternative solutions to meet performance requirements.
   a. Evaluate the plans that are in response to long-term (generally one year and beyond) customer requests for ~~t~~Transmission ~~s~~Service.
   b. Evaluate and plan for all requests required to integrate new (End-use Customer, generation, and transmission) ~~f~~Facilities into the Bulk Electric System.
   c. Determine ~~t~~Transfer ~~c~~Capability values (generally one year and beyond) as appropriate.
   d. Monitor, evaluate and report on ~~t~~Transmission expansion plan and resource plan implementation.
   e. Coordinate projects requiring ~~t~~Transmission outages that can impact reliability and firm ~~t~~Transactions.
6. Notify Generation Owners, Resource Planners, Transmission Planners and Transmission Owners of any planned ~~t~~Transmission changes that may impact their ~~f~~Facilities.
7. Define system protection and control needs and requirements, including ~~s~~Special ~~p~~Protection ~~s~~Systems (~~r~~Remedial ~~a~~Action ~~s~~Schemes), to meet reliability needs.

Functional Entity — Transmission Planner

Definition

The ~~functional~~ entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority~~a Transmission Planner~~ area.



Introduction to the Transmission Planner

The Transmission Planner is responsible for assessing the longer-term (generally one year and beyond) reliability of its Transmission Planner area. By its very nature, Bulk Electric System planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the other systems. Transmission Planners coordinate their plans with the adjoining Transmission Planners to assess impact on or by those plans. The area under the purview of a Transmission Planner may include one or more Resource Planner areas and overlap one or more adjacent Transmission Planners.

Relationships with Other Functional Entities

1. Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, Resource Planners, other Transmission Planners, Transmission Owners, and Transmission Service Providers.
2. Collects information including:
   a. Transmission facility characteristics and ~~r~~Ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.
   b. Demand and Electrical ~~e~~Energy forecasts, capacity resources, and ~~d~~Demand-Side Management ~~response~~ programs from Load-Serving Entities, and Resource Planners.
   c. Generator unit performance characteristics and capabilities from Generator Owners.
   d. Long-term transmission capacity purchases and sales from Transmission Service Providers
3. Informs Resource Planners and other Transmission Planners of the methodologies and tools for the simulation of the ~~t~~Transmission system.
4. Coordinates with Resource Planners and other Transmission Planners on Bulk Electric System expansion plans.
5. Coordinates the evaluation of Bulk Electric System expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.
6. Reports on and coordinates its Bulk Electric System expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.

7. Notifies other Transmission Planners, Transmission Owners, Transmission Operators and other entities that may be impacted of any planned Bulk Electric System changes.
8. Coordinates with Distribution Providers, Transmission Owners, Generator Owners and Load-Serving Entities in the evaluation and plans for all requests required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.
9. Submits and coordinates the plans for the interconnection of Ff~~f~~acilities to the Bulk Electric System within its Transmission Planner area with other Transmission Planners and Resource Planners, as appropriate.
10. Coordinates and develops ~~t~~Transfer ~~c~~Capability values with other Transmission Planners, Reliability Coordinators, Transmission Operators, Transmission Owners and Transmission Service Providers
11. Coordinates with Transmission Owners and Generator Owners to define system protection and control needs and requirements, including ~~s~~Special ~~p~~Protection ~~s~~Systems (~~r~~Remedial ~~a~~Action ~~s~~Schemes), to meet reliability needs.
12. Receives maintenance schedules and construction plans from Transmission Operator or Transmission Owner for input into and evaluation of Bulk Electric System expansion plans.

Function — Resource Planning

Tasks

1. Consider generation capacity from resources both within and outside of the Resource Planner area for assessing resource adequacy.~~.~~
2. Monitor and report, as appropriate, on its resource plan implementation.
3. Develop and maintain resource (demand and capacity) models to evaluate resource adequacy.
4. Collect or develop information required for resource adequacy purposes, including:
   a. demand and energy forecasts, capacity resources, and demand response programs,
   b. generator unit performance characteristics and capabilities, and
   c. long-term capacity purchases and sales and
   d. transmission (interface) limits.
5. Evaluate, develop, document, and report on a resource adequacy plan for its portion of the Transmission Planner and Planning Coordinator area.
6. Assist in the evaluation of the deliverability of resources.



Functional Entity — Resource Planner

Definition

The ~~functional~~ entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a ~~Resource Planner~~Planning Authority area.



Relationships with Other Functional Entities

1. Coordinates the resource models with its Planning Coordinator.
2. Coordinates with Transmission Owners and Transmission Planners on the deliverability of resources to Transmission C~~c~~ustomers.
3. Coordinates with and collects data for resource planning from the Load-Serving Entities, Generator Owners, Generator Operators, Transmission Planners, Transmission Operators, Interchange ~~Coordinator~~Authority(ies), and Reliability Assurers.
4. Coordinates with Transmission Planners, Transmission Service Providers, Reliability Coordinators, and Planning Coordinators on resource adequacy plans.
5. Coordinates with adjoining Resource Planners within the Planning Coordinator area to avoid the double-counting of resources.
6. Reports its resource plan to the Transmission Planner and Planning Coordinator for evaluation and compliance with Reliability Standards.
7. Reports on resource plan implementation to the Transmission Planner, Planning Coordinator and Reliability Assurer.
8. Works with the Planning Coordinator and Transmission Planners to identify potential alternative transmission solutions to meet Resource Planner plans.
9. Applies methodologies and tools for the analysis and development of resource adequacy plans from the Planning Coordinator.

Function — Reliability Operations

Tasks



1. Monitor all reliability-related parameters within the reliability area, including generation dispatch and generation/Ttransmission maintenance plans.
2. Identify, communicate, and direct actions if necessary to relieve reliability threats and limit violations in the reliability area.
3. Develop Interconnection Reliability Operating Limits (to protect from instability and Cascading).
4. Assist in determining reliability-related services requirements for balancing generation and load, and Ttransmission reliability (e.g., reactive requirements, location of operating reserves).
5. Perform reliability analysis (actual and contingency) for the reliability area.
6. Direct revisions to Ttransmission maintenance plans as permitted by Aagreements.
7. Direct revisions to generation maintenance plans as permitted by Aagreements.
8. Direct implementation of emergency procedures including load shedding.
9. Direct and coordinate system restoration.
10. Curtail Confirmed Interchange that adversely impacts reliability.

Functional Entity — Reliability Coordinator

Definition

The entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision~~The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area~~.



Introduction to the Reliability Coordinator

The Reliability Coordinator maintains the Real-time operating reliability of its Reliability Coordinator Area and in coordination with its neighboring Reliability Coordinator's W~~w~~ide~~-~~ A~~a~~rea view. The ~~w~~Wide~~-~~ ~~a~~Area view includes situational awareness of its neighboring Reliability Coordinator Areas. Its scope includes both transmission and balancing operations, and it has the authority to direct other functional entities to take certain actions to ensure that its Reliability Coordinator Area operates reliably.

Transmission operations. With respect to transmission operations, the Reliability Coordinator and Transmission Operator have similar roles, but different scopes. The Transmission Operator directly maintains reliability for its own defined area. However, the Reliability Coordinator also maintains reliability, in concert with the other Reliability Coordinators, for the Interconnection as a whole. Thus, the Reliability Coordinator needs a "W~~w~~ide~~-~~ A~~a~~rea" view that reaches beyond its boundaries to enable it to operate within Interconnection Reliability Operating Limits. The Transmission Operator may or may not have this "W~~w~~ide~~-~~ A~~a~~rea" view, but the Reliability Coordinator does have it. The Reliability Coordinator may direct a Transmission Operator within its Reliability Coordinator Area to take whatever action is necessary to ensure that Interconnection Reliability Operating Limits are not exceeded.

Balancing operations. The Reliability Coordinator ensures that the generation-demand balance is maintained within its Reliability Coordinator Area, which, in turn, ensures that the Interconnection frequency remains within acceptable limits. The Balancing Authority has the responsibility for generation-demand-interchange balance in the Balancing Authority Area. The Reliability Coordinator may direct a Balancing Authority within its Reliability Coordinator Area to take whatever action is necessary to ensure that this balance does not adversely impact reliability.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinates with other Reliability Coordinators, Transmission Planners, and Transmission Service Providers on T~~t~~ransmission ~~system~~ limitations.

2. Receives ~~f~~Facility and operational data from Generator Operators, Load-Serving Entities, Transmission Owners, Generator Owners, and Transmission Operators.
3. Receives generation dispatch from Balancing Authorities and issues dispatch adjustments to Balancing Authorities to prevent exceeding limits within the Reliability Coordinator Area (if not resolved through market mechanisms).
4. Receives integrated operational plans from Balancing Authorities for reliability analysis of Reliability Coordinator Area.
5. Receives T~~t~~ransmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis.
6. Develops Interconnection Reliability Operating Limits, based on Transmission Owners' and Generator Owners' specified equipment ratings, and provides them to Transmission Operators.
7. Assists Transmission Operators in calculating and coordinating System Operating Limits.
8. Provides reliability analyses to Transmission Operators, Generator Operators and Balancing Authorities in its area as well as other Reliability Coordinators.
9. Directs Generator Owners and Transmission Owners to revise generation and transmission maintenance plans that are adverse to reliability.
10. Receives balancing information from Balancing Authorities for monitoring.
11. Receives final approval or denial of Arranged Interchange from Interchange ~~Coordinator~~Authority.
12. Provide IROLs and TTC to the Transmission Service Provider for ATC calculation.
13. Develops operating agreements or procedures with Transmission Owners.
14. Coordinates with Transmission Operators on system restoration plans, contingency plans and reliability-related services.

Real Time

15. Coordinates reliability processes and actions with and among other Reliability Coordinators.
16. Receives Real-time operational information from Balancing Authorities, Interchange ~~Coordinator~~Authority(ies) and Transmission Operators for monitoring.
17. Issues reliability alerts to Generator Operators, Transmission Operators, Transmission Service Providers, Balancing Authorities, Interchange ~~Coordinator~~Authority(ies), Regional Entities and NERC.
18. Issues corrective actions and emergency procedures directives (e.g., curtailments or load shedding) to Transmission Operators, Balancing Authorities, Generator Operators, Distribution Providers, and Interchange ~~Coordinator~~Authority(ies).
19. Specifies reliability–related requirements (e.g., reactive requirements, location of operating reserves) to Balancing Authorities.
20. Receives verification of emergency procedures from Balancing Authorities.

21. Receives notification of Confirmed Interchange changes from Balancing Authorities.
22. Orders redispatch of generation by Balancing Authorities.
23. Directs use of flow control devices by Transmission Operators.
24. Responds to requests from Transmission Operators to assist in mitigating equipment overloads.

Function — Balancing

Tasks



1. Control any of the following combinations within a Balancing Authority Area:
   a. lLoad and generation (an isolated system)
   b. lLoad and Confirmed Interchange
   c. gGeneration and Confirmed Interchange
   d. gGeneration, load, and Confirmed Interchange
2. Calculate Aarea Ceontrol Eerror within the reliability area.
3. Operate in the Balancing Authority Area to maintain load-interchange-generation balance.
4. Review generation commitments, dispatch, and load forecasts.
5. Formulate an operational plan (generation commitment, outages, etc.) for reliability evaluation.
6. Approve Arranged Interchange from ramping ability perspective.
7. Implement Confirmed Interchange.
8. Operate the Balancing Authority Area to contribute to Interconnection frequency.
9. Monitor and report control performance and disturbance recovery.
10. Provide balancing and energy accounting (including hourly checkout of Confirmed Interchange, Implemented Interchange and actual interchange), and administer inadvertent energy paybacks.
11. Determine needs for reliability-related services.
12. Deploy reliability-related services.
13. Implement emergency procedures.

Functional Entity — Balancing Authority

Definition

The responsible ~~functional~~ entity that integrates resource plans ahead of time, maintains ~~generation~~ load-interchange-generation balance within a Balancing Authority Area, and ~~contributes to~~supports Interconnection frequency in real time.



Relationships with Other Functional Entities

Ahead of Time

1. Receives operating and availability status of generating units and operational plans and commitments from Generator Operators (including annual maintenance plans) within the Balancing Authority Area.
2. Receives annual maintenance plans from Generator Owners within the Balancing Authority Area.
3. Receives reliability evaluations from the Reliability Coordinator.
4. Receives final approval or denial of a request for an Arranged Interchange from the Interchange ~~Coordinator~~Authority(ies).
5. Compiles load forecasts from Load-Serving Entities.
6. Develops agreements with adjacent Balancing Authorities for ACE calculation parameters.
7. Submits integrated operational plans to the Reliability Coordinator for reliability evaluation and provides balancing information to the Reliability Coordinator for monitoring.
8. Confirms Arranged Interchange with Interchange ~~Coordinator~~Authority(ies).
9. Confirms Rr~~r~~amping capability with Interchange ~~Coordinator~~Authority(ies).
10. Implements generator commitment and dispatch schedules from the Load-Serving Entities and Generator Operators who have arranged for generation within the Balancing Authority Area.
11. Acquires reliability-related services from Generator Operator.
12. Receives dispatch adjustments from Reliability Coordinators to prevent exceeding limits.
13. Receives generator information from Generator Owners including unit maintenance schedules and retirement plans.
14. Receives information from Load Serving Entities on self-provided reliability-related services.
15. Coordinates system restoration plans with Transmission Operator.
16. Provides generation dispatch to Reliability Coordinators.

Real Time

17. Coordinates use of controllable loads with Load-Serving Entities (i.e., interruptible load that has been bid in as a reliability-related service or has agreed to participate in voluntary load shedding program under resource/reserve deficiency situations).
18. Receives loss allocation from Transmission Service Providers (for repayment with in-kind losses).
19. Receives Real-time operating information from the Transmission Operator, adjacent Balancing Authorities and Generator Operators.
20. Receives operating information from Generator Operators.
21. Provides Real-time operational information for Reliability Coordinator monitoring.
22. Receives reliability alerts from Reliability Coordinator.
23. Complies with reliability-related requirements (e.g., reactive requirements, location of operating reserves) specified by Reliability Coordinator.
24. Verifies implementation of emergency procedures to Reliability Coordinator.
25. Informs Reliability Coordinator and Interchange ~~Coordinator~~Authority(ies) of Confirmed Interchange changes (e.g., due to generation or load interruptions) involving its Balancing Authority Area.
26. Directs resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in R~~r~~eal~~ ~~-time.
27. Directs Transmission Operator (or Distribution Provider) to reduce voltage or shed load if needed to ensure balance within its Balancing Authority Area.
28. Directs Generator Operators to implement redispatch for congestion management as directed by the Reliability Coordinator.
29. Implements corrective actions and emergency procedures as directed by the Reliability Coordinator.
30. Implements system restoration plans as directed by the Transmission Operator.
31. Directs Transmission Operator to implement flow control devices.
32. Receives information of Implemented Interchange and Confirmed Interchange Curtailments from Interchange ~~Coordinator~~Authority(ies).

After the hour

33. Confirms Implemented Interchange with Confirmed Interchange provided by the Interchange ~~Coordinators~~ Authority(ies) after the hour for “checkout.”
34. Confirms Implemented Interchange and Confirmed Interchange with adjacent Balancing Authorities after the hour for “checkout”.

Function — Market Operations

The Market Operations Function, its tasks, and the interrelationships with other entities are included in the Functional Model only as an interface point of reliability Functions with commercial functions.



Functional Entity — Market Operator (Resource Integrator)

Definition

The market entity whose interrelationships with other entities are included in the Functional Model only as an interface point of reliability functions with commercial functions.



Relationships with Other Functional Entities

Market Operator tasks and relationships are specific to a particular market design and will depend on the market structure over which the Market Operator presides.

Function — Transmission Operations

Tasks



1. Monitor and provide telemetry (as needed) of all reliability-related parameters within the reliability area.
2. Monitor the status of, and deploy, facilities classed as transmission assets, which may include the transmission lines connecting a generating plant to the transmission system, associated protective relaying systems and Special Protection Systems.
3. Develop system limitations such as System Operating Limits and Total Transfer Capabilities, and operate within those limits.
4. Develop and implement emergency procedures.
5. Develop and implement system restoration plans.
6. Operate within established Interconnection Reliability Operating Limits.
7. Perform reliability analysis (actual and contingency) for the Transmission Operator Area.
8. Adjust flow control devices within the transmission area to maintain reliability.
9. Deploy reactive resources to maintain transmission voltage within defined limits.

Functional Entity — Transmission Operator



Definition

The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities~~The functional entity that ensures the Real-time operating reliability of the transmission assets within a Transmission Operator Area~~.

Introduction to the Transmission Operator

The Transmission Operator is responsible for the Real-time operating reliability of the transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably.

The Transmission Operator and Reliability Coordinator have similar roles with respect to transmission operations, but different scopes. The Transmission Operator scope is narrower than the Reliability Coordinator, and the Transmission Operator does not necessarily "see" very far beyond its own boundaries. Therefore, the Transmission Operator can calculate System Operating Limits, but will not necessarily calculate Interconnection Reliability Operating Limits, which requires the wider scope of the Reliability Coordinator.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinates restoration plans with Reliability Coordinator, Transmission Operators, Balancing Authorities, and Distribution Providers.
2. Receives maintenance requirements and construction plans and schedules from the Transmission Owners and Generation Owners.
3. Receives Interconnection Reliability Operating Limits as established by the Reliability Coordinator.
4. Receives reliability evaluations from the Reliability Coordinator.
5. Develops agreements with adjacent Transmission Operators for joint transmission facilities.
6. Defines Total Transfer Capabilities and System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator.
7. Arranges for reliability-related services from Generator Operators.
8. Develops contingency plans, and monitors operations of the transmission facilities within the Transmission Operator Area control and as directed by the Reliability Coordinator.
9. Provides facility and operating information to the Reliability Coordinator.

10. Provides to the Transmission Planner information on the capability to curtail (reduce) and shed load during emergencies.
11. Provides Total Transfer Capabilities and System Operating Limits to, and coordinates Available Transfer Capability with, Transmission Service Provider.
12. Receives operating and availability status of generating units from Generation Operators including status of automatic voltage regulators.
13. Develops operating agreements or procedures with Transmission Owners.

Real Time

14. Coordinates load shedding with, or as directed by, the Reliability Coordinator.
15. Provides Real-time operations information to the Reliability Coordinator and Balancing Authority.
16. Notifies Generator Operators of transmission system problems (e.g., voltage limitations or equipment overloads that may affect generator operations).
17. Requests Reliability Coordinator to assist in mitigating equipment overloads. (e.g., redispatch, transmission loading relief).
18. Deploys reactive resources from Transmission Owners and Generator Owners to maintain acceptable voltage profiles.
19. Directs Distribution Providers to shed load if needed to ensure reliability within the Transmission Operator Area.
20. Implements flow control device operations for those ties under the Transmission Operator's purview as directed by the Balancing Authorities or Reliability Coordinator.
21. Receives reliability alerts from Reliability Coordinator.
22. Directs Balancing Authorities and Distribution Providers to implement system restoration plans.

Function — Interchange

Tasks



1. Receive an Arranged Interchange.
2. Ensure an Arranged Interchange is balanced and valid (Balancing Authority and Transmission Service Provider validation of sources and sinks, transmission arrangements, reliability-related services, etc.).
3. Coordinate (i.e., collect and consolidate) approval, change, and denial requests for an Arranged Interchange to become Confirmed Interchange. Approvals may be explicit or by exception.
4. Receive confirmations of requested Arranged Interchange.
5. Communicate status of an Arranged Interchange that becomes Confirmed Interchange or otherwise.
6. Communicate Confirmed Interchange information to the appropriate reliability assessment tools (e.g., the interchange distribution calculator in the Eastern Interconnection).
7. Maintain record of an individual Confirmed Interchange.

Functional Entity — Interchange ~~Coordinator~~Authority

Definition

The ~~functional~~ responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes~~ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates implementation of valid and balanced Confirmed Interchange between Balancing Authority Areas~~.



Relationships with Other Functional Entities

Ahead of Time

1. Receives Arranged Interchange from Purchasing-Selling and Load Serving Entities.
2. Submits request for an Arranged Interchange to become Confirmed Interchange to the Balancing Authorities and Transmission Service Providers for approvals.
3. Receives approval or denial from Transmission Service Providers of transmission arrangement(s) for Arranged Interchange.
4. Receives approval or denial from Balancing Authorities of the ability to meet ramping requirements for submitted Arranged Interchange.
5. Communicates final approval or denial of a request for an Arranged Interchange to become Confirmed interchange to the Reliability Coordinator, Balancing Authorities, Transmission Service Providers and Purchasing-Selling Entities and Load-Serving Entities for implementation and NERC identified reliability analysis services.

Real Time

6. Receives curtailments and redispatch implementation requests from Reliability Coordinators for an Arranged Interchange.
7. Receives information on Confirmed Interchange interruptions from the Balancing Authorities and communicates the Confirmed Interchange status to Balancing Authorities, Transmission Service Providers, Reliability Coordinators, and Purchasing-Selling/Load-Serving Entities.
8. Informs Transmission Service Providers, Purchasing-Selling/Load-Serving Entities, Reliability Coordinators, and Balancing Authorities of Confirmed Interchange revisions (including curtailments).

After the hour

9. Maintains and provides a record of individual Confirmed Interchange for which it coordinated with the Balancing Authorities.

10. Coordinates Confirmed Interchange with Balancing Authorities after the hour for "checkout".

Function — Transmission Service

Tasks



1. Receive transmission service requests and process each request for service according to the requirements of the tariff.
    a. Maintain commercial interface for receiving and confirming requests for transmission service according to the requirements of the tariff (e.g., OASIS).
2. Determine and post Aavailable Ttransfer Ccapability values.
3. Approve or deny transmission service requests.
4. Approve Arranged Interchange from Ttransmission Sservice agreement~~transmission service arrangement~~ perspective.
5. Allocate transmission losses (MWs or funds) among Balancing Authority Areas.

Functional Entity — Transmission Service Provider



Definition

The ~~functional~~ entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable ~~t~~Transmission ~~s~~Service agreements.

Relationships with Other Functional Entities

Ahead of Time

1. Receives Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits from Planning Coordinator, Transmission Planner, Transmission Operator and Reliability Coordinator, and coordinates Available Transfer Capability with these entities and other Transmission Service Providers.
2. Receives transmission Facility Ratings from Transmission Owners.
3. Receives transmission expansion plans identified by the Planning Coordinator to help determine ability to accommodate long-term T~~t~~ransmission ~~s~~Service requests.
4. Approves or denies T~~t~~ransmission S~~transmission s~~ervice requests from Purchasing-Selling Entities, Generator Owners, and Load-Serving Entities.
5. Confirms validity of T~~t~~ransmission S~~transmission s~~ervice requests indicated in the Arranged Interchange with Interchange ~~Coordinator~~Authority(ies).
6. Develops agreements or procedures with Transmission Owners.
7. Receives final approval or denial of Arranged Interchange from Interchange ~~Coordinator~~Authority(ies).

Real Time

8. Receives Confirmed Interchange implementation (including curtailments) from the Interchange ~~Coordinator~~Authority(ies).
9. Receives reliability alerts from Reliability Coordinator.
10. Provides loss allocation to Balancing Authority(ies).

Function — Transmission Ownership

Tasks

1. Develop interconnection agreements.
2. Establish ratings of transmission facilities.
3. Maintain transmission facilities and rights-of-way.
4. Design and install owned facilities classified as transmission and obtain associated rights-of-way.
5. Design and authorize maintenance of transmission protective relaying systems and Special Protection Systems.



Functional Entity — Transmission Owner

Definition

The ~~functional~~ entity that owns and maintains transmission ~~f~~Facilities.



Relationships with Other Functional Entities

1. Coordinates with Transmission Planners and the Planning Coordinator, Generator Owners, other Transmission Owners, and Load-Serving Entities desiring to connect with the Bulk Electric System.
2. Receives approved transmission expansion plans from the Transmission Planner.
3. Develops agreements or procedures with the Transmission Service Providers.
4. Develops operating agreements or procedures with the Transmission Operators, Reliability Coordinators and Distribution Providers.
5. Develops agreements with adjacent Transmission Owners for joint transmission facilities.
6. Provides transmission expansion plans and changes to the Planning Coordinator and Transmission Planners.
7. Provides transmission Facility Ratings to Transmission Operators, Reliability Coordinators, Transmission Service Providers, Distribution Providers, Transmission Planners, and Planning Coordinator.
8. Provides maintenance and construction plans and schedules to the Reliability Coordinator, Transmission Operator, and Transmission Planner.
9. Develops interconnection agreements with the Distribution Providers and Generation Owners for connecting to the Bulk Electric System.
10. Provides reactive resources to Transmission Operators.
11. Revises transmission maintenance plans as requested by the Reliability Coordinator.

Function — Distribution



Tasks

1. Provide and operate electrical delivery facilities between the transmission system and the End-use Customer.
2. Implement voltage reduction.
3. Design and maintain protective relaying systems, under-frequency load shedding systems, under-voltage load shedding systems, and Special Protection Systems that interface with the transmission system.
4. Provide and implement load-shed capability.
5. Maintain voltage and power factor within specified limits at the interconnection point.

Functional Entity — Distribution Provider



Definition

Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage~~The functional entity that provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer~~.

Introduction to the Distribution Provider

The Distribution Provider delivers Eelectrical Ee~~e~~nergy to the End-use Customer from the transmission system. For those End-use Customers who are served at transmission voltages, the Transmission Owner may also serve as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. The Distribution Provider provides the switches and re-closers that could be used to shed load for emergency action.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinates with Transmission Planners on transmission expansion.
2. Coordinates system restoration plans with Transmission Operator.
3. Coordinates with End-use Customers and Load-Serving Entities to identify new facility connection needs.
4. Develop interconnection agreements with Transmission Owners on a facility basis.
5. Provides operational data to Transmission Operator.
6. Coordinate with Load-Serving Entities to identify critical loads that are to be precluded from load shedding where avoidable.

Real Time

7. Implements voltage reduction and sheds load as directed by the Transmission Operator or Balancing Authority.
8. Implements system restoration plans as coordinated by the Transmission Operator.
9. Directs Load-Serving Entities to communicate requests for voluntary load curtailment.

Function — Generator Operation

Tasks

1. Formulate daily generation plan.
2. Report operating and availability status of units and related equipment, such as automatic voltage regulators.
3. Operate generators to provide ~~r~~Real Power and ~~r~~Reactive P~~p~~ower or Interconnected Operations Service~~reliability-related services~~ per contracts or arrangements.
4. Monitor the status of generating facilities.
5. Support Interconnection frequency.



Functional Entity — Generator Operator

Definition

The ~~functional~~ entity that operates generating Facility(ies)~~unit(s)~~ and performs the functions of supplying energy and reliability related services.



Relationships with Other Functional Entities

Ahead of Time

1. Provides generation commitment plans to the Balancing Authority.
2. Provides Balancing Authority and Transmission Operators with requested amount of reliability-related services.
3. Provides operating and availability status of generating units to Balancing Authority and Transmission Operators for reliability analysis.
4. Reports status of automatic voltage or frequency regulating equipment to Transmission Operators.
5. Provides operational data to Reliability Coordinator.
6. Receives reliability analyses from Reliability Coordinator.
7. Receives notice from Purchasing-Selling Entity if Arranged Interchange approved or denied.
8. Receives reliability alerts from Reliability Coordinator.
9. Receives notification of transmission system problems from Transmission Operators.

Real Time

10. Provides Real-time operating information to the Transmission Operators and the required Balancing Authority.
11. Adjusts ~~r~~Real Power and ~~r~~Reactive ~~p~~Power as directed by the Balancing Authority and Transmission Operators.

Function — Generator Ownership



Tasks

1. Establish generating ~~f~~Facility ~~r~~Ratings, limits, and operating requirements.
2. Design and authorize maintenance of generation plant ~~protective relaying systems~~Protection Systems, Protection Systems on the transmission lines connecting the generation plant to the T~~t~~ransmission ~~s~~System, and Special Protection Systems.
3. Maintains owned generating~~-~~ facility.
4. Provide verified generating facility performance characteristics / data.

Functional Entity — Generator Owner

Definition

~~The functional e~~Entity that owns and maintains generating Facility(ies)~~units~~.



Relationships with Other Functional Entities

1. Provides generator information to the Transmission Operator, Reliability Coordinator, Balancing Authority, Transmission Planner, and Resource Planner.
2. Provides unit maintenance schedules and unit retirement plans to the Transmission Operator, Balancing Authority, Transmission Planner, and Resource Planner.
3. Develops an interconnection agreement with Transmission Owner on a facility basis.
4. Receives approval or denial of ~~t~~Transmission- ~~s~~Service request from Transmission Service Provider.
5. Provides reliability related services to Purchasing-Selling Entity pursuant to an ~~a~~Agreement.
6. Reports the annual maintenance plan to the Reliability Coordinator, Balancing Authority and Transmission Operator.
7. Revises the generation maintenance plans as requested by the Reliability Coordinator.

Function — Purchasing-Selling

Tasks

1. Purchase and sell energy or capacity.
2. Arrange for ~~t~~Transmission ~~s~~Service that is required by tariffs.
3. Request implementation of Arranged Interchange.



Functional Entity — Purchasing-Selling Entity



Definition

The ~~functional~~ entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities~~reliability related services~~.

Relationships with Other Functional Entities

Ahead of Time

1. Arranges for ~~t~~Transmission ~~s~~Service from Transmission Service Providers and makes arrangements for reliability-related services with Generator Owners or Load-Serving Entities.
2. Submits Requests For Interchange to Interchange ~~Coordinator~~ Authority(ies).
3. Notifies Generator Operators and Load-Serving Entities if Arranged Interchange requests are approved or denied.
4. Receives final approval or denial of Arranged Interchange from Interchange ~~Coordinator~~Authority(ies).
5. Receives load profiles and forecasts from Load-Serving Entities.

Real Time

6. Notifies Interchange ~~Coordinator~~ Authority(ies) ~~-~~of Confirmed Interchange and Implemented Interchange cancellations or terminations.
7. Receives notice of Confirmed Interchange curtailments from Interchange ~~Coordinator~~Authority(ies).

Function — Load-Serving

Tasks

1. Collect individual load profiles.
2. Identify capability for and communicate requests for voluntary load curtailment.
3. Participate in under-frequency load shedding systems and under-voltage load shedding systems through identification of critical customer loads that are to be excluded from the load shedding systems.
4. Identify need for facilities and provide capability of self-provided reliability-related services for its load.
5. Develop overall load profiles and forecasts of end-user energy requirements.
6. Acquire necessary ~~t~~Transmission ~~s~~Service, and reliability-related services.
7. Submits Requests For Interchange to Interchange ~~Coordinator.~~Authority(ies).
8. Manage resource portfolios to meet demand and energy requirements of End-use Customers.



Functional Entity — Load-Serving Entity



Definition

~~The functional entity that s~~Secures energy and ~~t~~Transmission ~~s~~Service (and related Interconnected Operations ~~reliability related s~~Services) to serve the electrical demand and energy requirements of its end~~-~~-use customers.

Relationships with Other Functional Entities

Ahead of Time

1. Submits load profiles and characteristics, plans, and forecasts as needed to the Balancing Authorities, Purchasing-Selling Entities, Planning Coordinator, Resource Planners, and Transmission Planners.
2. Identifies new facility connection needs for End-use Customers.
3. Provides generation commitments and dispatch schedules to the Balancing Authority.
4. Provides information as to self-provided reliability-related services to the Balancing Authority.
5. Provides planned purchases to the Resource Planner and Transmission Planner for system modeling and reliability evaluation.
6. Arranges for ~~t~~Transmission ~~s~~Service from Transmission Service Providers and makes arrangements for reliability-related services with Generator Owners or Load-Serving Entities.
7. Submits Requests For Interchange to Interchange ~~Coordinator.~~Authority(ies).
8. Notifies Generator Operators if Arranged Interchange requests are approved or denied.
9. Receives final approval or denial of Arranged Interchange from Interchange ~~Coordinator~~Authority(ies).
10. Coordinates with Distribution Provider on identifying new facility interconnection needs.
11. Receives notification from Purchasing-Selling Entity if Arranged Interchange requests approved or denied.

Real Time

12. Receives requests from the Balancing Authority and Distribution Provider for voluntary load curtailment.
13. Communicate requests for voluntary load curtailment to E~~e~~nd-use C~~e~~ustomers as directed by the Balancing Authority and Distribution Provider.
14. Notifies Interchange ~~Coordinator~~Authority(ies) of Confirmed Interchange cancellations or terminations.
15. Receives notice of Confirmed Interchange curtailments from Interchange ~~Coordinator~~Authority(ies).

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:	Standards Efficiency Review (SER) Recommendations for Retirement-Draft		
Date Submitted:	August 7, 2018		
SAR Requester			
Name:	Standards Efficiency Review (SER) Team (Charles Rogers, Michael Cruz-Montes, Latroy Brumfield)		
Organization:	Standards Efficiency Review (SER) Team		
Telephone:		Email:	
SAR Type (Check as many as apply)			
☐ New Standard ☐ Revision to Existing Standard(s) ☐ 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?):			
Many NERC Reliability Standards have been mandatory and enforceable for over 10 years in North America, Phase 1 of the Standards Efficiency Review (SER) project seeks to identify requirements that are potential candidates for retirement because they are no longer essential for reliability. Retiring these requirements would increase efficiencies by reducing regulatory obligations and/or compliance burden.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
Phase 1 of this project reduces the number of mandatory and enforceable requirements with which registered entities must comply.			

Project Scope (Define the parameters of the proposed project):
The Standards Efficiency Review (SER) team used a risk-based approach to evaluate the reliability benefit of each requirement. Based on its analyses, the SER team is recommending the requirements listed below be retired. • BAL-005-1 R4, R6 • COM-002-4 R2 • EOP-005-3 R8 • EOP-006-3 R7 • FAC-008-3 R7, R8 • FAC-013-2 R1, R2, R4, R5, R6 (All) • INT-004-3.1 R1, R2, R3 (All) • INT-006-4 R3.1, R4, R5 • INT-009-2.1 R2 • INT-010-2.1 R1, R2, R3 (All) • IRO-002-5 R1, R4, R6 • IRO-008-2 R6 • IRO-014-3 R3 • IRO-017-1 R3 • MOD-001-1a R1, R2, R3, R4, R5, R6, R7, R8, R9 (All) • MOD-001-2 R1, R2, R3, R4, R5, R6 (All) • MOD-004-1 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12 (All) • MOD-008-1 R1, R2, R3, R4, R5 (All) • MOD-020-0 R1 (All) • MOD-028-2 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11 (All) • MOD-029-2a R1, R2, R3, R4, R5, R6, R7, R8 (All) • MOD-030-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10 (All) • PRC-004-5(i) R4 • PRC-015-1 R1, R2, R3 (All) • PRC-018-1 R1, R2, R3, R4, R5, R6 (All) • TOP-001-4 R16, R17, R19, R22

- VAR-001-4.2 R2, R3
- VAR-001-4.2 E.A.15

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):

In Phase 1 of the Standards Efficiency Review (SER) project, three SER teams [Real-time Operations (RT), Long-term Planning (LT), and Operations Planning (OP)] evaluated each requirement in the body of NERC Reliability Standards for unconditional retirement i.e. these requirements may be retired without any modifications to other standards or requirements. The observations/rationales for retiring the requirements (identified in the Project Scope above) are listed below.

BAL-005-1 R4, R6 (RT)
The reliability objective of this requirement is duplicative of TOP-010-1(i) R2.

The Balancing Authority is already required by TOP-010-1(i) R2 to have an Operating Process/Procedure to address quality of Real-time data (including Reporting ACE) which includes criteria to evaluate the data, provisions to indicate the quality of the data to the System Operator, and actions to address data quality issues with other entities.

The same logic applies for R6 since TOP-010-1(i) R2 requires an Operating Process/Procedure to include criteria to evaluate the data, provisions to indicate the quality of the data to the System Operator, and actions to address data quality issues with other entities.

COM-002-4 R2 (RT)
The related compliance activities are duplicative of the activities covered by the Systematic Approach to Training in Reliability Standard PER-005-2. Issuing and receiving Operating Instructions according to a company's specific communications protocols is a fundamental Real-time reliability-related task and would be included in an entity's PER-005-2 training program to ensure System Operators are competent to perform the activities necessary for compliance with COM-002-4 R4 – R7. Additionally, Communication Methods (e.g. Three-Part Communications) is part of the knowledge content expected to be performed by all System Operators for the Certififcation Examination.

EOP-005-3 R8 (OP)
The related compliance activities are duplicative of the activities covered by the Systematic Approach to Training in Reliability Standard PER-005-2. System restoration is a reliability-related task

[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.

and would be included in an entity's training program for its System Operators to ensure that System Operators are certified and competent to perform restoration activities.

EOP-006-3 R7 (OP)
The related compliance activities are duplicative of the activities covered by the Systematic Approach to Training in Reliability Standard PER-005-2. System restoration is a reliability-related task and would be included in an entity's training program for its System Operators to ensure that System Operators are certified and competent to perform restoration activities.

FAC-008-3 R7, R8 (OP)
These requirements are duplicative of the data provision standards MOD-32-1, IRO-010-2, and TOP-003-3.

In MOD-032-1 R1, the PC and TP develop modeling data requirements and reporting according to Attachment 1. In MOD-032-1 R2, the TO and GO provide power capabilities data in item 3 and facility ratings data in items 3f, 4c, 6g in the steady-state column of Attachment 1 as requested by the TP or PC.

IRO-010-2 R1 and TOP-003-3 R1 require the RC and TOP to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments. This data necessarily includes facility ratings as inputs to SOL monitoring. IRO-010-2 R3 and TOP-003-3 R5 require the TO and GO to respond to the RC's and TOP's requests.

FAC-013-2 R1, R2, R4, R5, R6 (ALL) (LT)
The requirement for Planning Coordinators (PC) to have a methodology for and to perform an annual assessment of Transfer Capability for a single year in the Near-Term Transmission Planning Horizon does not benefit System reliability beyond that provided by other Reliability Standards. This Reliability Standard is primarily administrative in nature and does not require specific performance metrics or coordination among functional entities.
In general, FAC-013-2 fails to meet System reliability objectives in the following ways:

- Individual PCs develop their own methodologies that may be very disparate from each other.
- Impacted functional entities, such as Transmission Planners (TP), do not have meaningful input into the methodology or analysis.
- The standard does not specify performance metrics or define what acceptable system performance is.
- Entities that receive the methodology or assessment results are not obligated to use or even consider the information in their assessments.
- R4 only requires the assessment to be performed for one year in the Near-Term Transmission Planning Horizon. This year can be arbitrarily chosen by the PC and the analysis does not guarantee transmission service that is necessary for System reliability.

- Assessing transfer capability above the "known commitments for Firm Transmission Service and Interchange" required by TPL-001-4 (R1.1.5), serves a market function as opposed to securing System reliability.
- Assessing transfer capability in the planning horizon is a method to test the robustness of the system. Robustness testing of a system is not an indicator of reliability because there is no metric for robustness.

Additionally, the proposed retirement of FAC-013 does not preclude any entity from performing studies to assess transfer capability for their own purposes. The reliability benefit of doing such an assessment varies from entity to entity with some entities not having a benefit for the assessment it at all. The 2013 NERC Independent Experts Review Project identified R2 and R3 as administrative and recommended them for retirement. R3 was approved for retirement by FERC in 2014.

INT-004-3.1 R1. (RT and OP)
This requirement is no longer enforceable as the Purchasing Selling Entity is no longer a NERC registered function. The NERC INT Periodic Review Team completed its analysis and determined the requirement is duplicative of the NAESB WEQ Business Practice Standards, specifically covered in existing NAESB WEQ-004-1 and WEQ-004-5, and in proposed NAESB WEQ-004-1.8. Additionally, the NERC Independent Expert Review Panel concluded the requirement qualified for Paragraph 81 retirement as it does little, if anything, to benefit or protect the reliable operation of the BES.

INT-004-3.1 R2 (RT and OP)
This requirement is no longer enforceable as the Purchasing Selling Entity is no longer a NERC registered entity. The NERC INT Periodic Review Team completed its analysis and determined the requirement is duplicative of a currently proposed revision to the NAESB WEQ Business Practice Standards. The language in R2, requiring Confirmed Interchange associated with Dynamic Schedules or Pseudo-Ties being updated for future hours when any of the three conditions cited in the requirement occur, is contained almost verbatim in the proposed NAESB WEQ-004-23. Additionally, the Independent Expert Review Team concluded the requirement qualified for Paragraph 81 retirement as it does little, if anything, to benefit or protect the reliable operation of the BES.

INT-004-3.1 R3 (OP)
This requirement qualifies for Paragraph 81 retirement as it only obligates entities to register information with an entity, which the failure to do so would create no discernable reliability impact. The standard states the purpose of the requirement is allow for pseudo-tie coordination, which is already guided and more clearly explained within the NERC Pseudo-Tie Coordination Reference Document. Reliability Coordinator visibility to Pseudo-Ties is provided under existing NERC Standard IRO-010-2 Requirement R2. Therefore, this requirement is redundant and does little, if anything, to benefit or protect the reliable operation of the BES.

INT-006-4 R3.1 (RT and OP)
The INT Periodic Review Team (PRT) (Project 2017-04) conclusion supports retirement of this

requirement. The INT PRT found no impact on reliability in requiring the RC being notified when a Reliability Adjustment Arranged Interchange has been denied. Additionally, RCs are notified via the electronic tag when a Reliability Adjustment Arranged Interchange is denied, as required in the NAESB e-Tagging Specifications.

INT-006-4 R4 (RT and OP)
The INT Periodic Review Team (PRT) (Project 2017-04) conclusion supports retirement of this requirement as it is duplicative of the NAESB e-Tagging Specifications Section 1.6.3.1 and Section 1.3, and is not a reliability-related task performed by a NERC registered entity.

INT-006-4 R5 (RT)
The INT Periodic Review Team (PRT) (Project 2017-04) conclusion supports retirement of this requirement as it is duplicative of the NAESB e-Tagging Specifications Section 1.6.4, and is not a reliability-related task performed by a NERC registered entity. Additionally, it is contained on the list of standards not commonly identified through an IRA process.

INT-009-2.1 R2 (RT)
This requirement can be retired under Paragraph 81 Criteria B7, as the requirement for Balancing Authorities to establish an agreed upon interchange metering source is redundant with approved NERC Reliability Standard BAL-005-1, R7.

INT-010-2.1 R1, R3 (RT)
These requirements satisfy Paragraph 81 Criteria 'B6 – Commercial or Business Practice' and 'B7 – Redundant' because more stringent requirement(s) that meet the objectives are already included in WEQ-004-1 of the NAESB WEQ Business Practice Standards. In the absence of these requirements, all Interchange would have an RFI submitted for it, which is the more beneficial and prevalent existing outcome. The submittal of an RFI after Interchange has begun is for commercial purposes rather than reliability issues. The requirement to submit an RFI exists in the NAESB Business Practice Standards. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

INT-010-2.1 R2 (RT)
This requirement satisfies Paragraph 81 Criteria 'B6 – Commercial or Business Practice' and 'B7 – Redundant' because more stringent tagging requirement(s) that meet the objectives are already included in WEQ-004-8 of the NAESB WEQ Business Practice Standards. In the absence of this requirement, all Reliability Adjustment Arranged Interchange would have a modification submitted for it, which is the more beneficial and prevalent existing outcome. The submittal of a modification to a RFI after the modification has begun is for commercial purposes rather than reliability issues. The requirement to modify an RFI exists in the NAESB Business Practice Standards. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

IRO-002-5 R1 (OP)

The requirement is a control for aiding compliance with IRO-008-2 R1 related to the performance of an Operational Planning Analysis (OPA), and it is duplicative to R3 in IRO-010-2. IRO-010-2 requires the RC to identify the data it needs to perform its OPA (R1), which entities need to provide such data (R2), and then obligates those registered entities to then supply the data (R3). For an entity to fulfill IRO-010-2 R3, it must be able to exchange data with the requesting RC. Additionally, to comply with IRO-008-2 R1, the RC must have received all of the data it needs to perform the OPA. Finally, the measure (M1) for IRO-002-5 R1 states that an entity needs to have documentation describing its data exchange capabilities with other entities, which is administrative in nature.

IRO-002-5 R4 (OP)
This requirement can be retired because it does not contribute to reliability of the BES. The authority to approve or deny outages to any equipment, whether load-carrying or not, is a fundamental attribute of the System Operator role.

IRO-002-5 R6 (RT)
This requirement to have monitoring systems is unnecessary because IRO-002-5 R5 requires the monitoring of the systems which pre-supposes the ability (tools) to do so.

IRO-008-2 R6 (RT)
There is a potential for this requirement to become purely administrative in nature and not provide any reliability benefits. An Operating Plan required by IRO-014-3 R1, Part 1.1. or IRO-008-2 R5 would already include specific actions to notify impacted parties. The notifications for this requirement are after-the-fact and if the TOP, BA or other RC are a party to the implemented Operating Plan, then they would already be following the direction of the RC until notified.

IRO-014-3 R3 (RT)
The reliability objective of "notification" is mandated as a part of the RC having and implementing Operating Procedures, Operating Processes, or Operating Plans that include criteria and processes for notifications (R1, Part 1.1).

IRO-017-1 R3 (LT)
The reliability objective of this requirement is duplicative of the reliability objective of TPL-001-4, R8 which mandates each Planning Coordinator and Transmission Planner distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners and to any other functional entity that has a reliability related need and submits a written request.

MOD-020-0 R1 (ALL) (LT)
This requirement is duplicative of the data provision requirements included in Reliability Standards MOD-031-2 and IRO-010-2.

MOD-020-0 R1 requires the Load-Serving Entity, Transmission Planner, and Resource Planner to provide Interruptible Demand and Direct Control Load Management upon requests by the Transmission Operators, Balancing Authorities, and Reliability Coordinators.

In MOD-031-2 R1.4.5 requires the Planning Coordinator or Balancing Authority to request, as necessary, total available peak hour forecast of controllable and dispatchable Demand Side Management from the applicable entities. R2 then requires each applicable entity identified in the data request to provide the requested data to the PC or BA.

In IRO-010-2 R1 requires the Reliability Coordinator to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments, and R2 requires the RC to distribute its data specifications to all applicable entities. R3 then requires each applicable entity to respond to the request as specified.

PRC-004-5(i) R4 (OP)
The compliance activities associated with this requirement fall into tracking of milestones and do not improve reliability. Requirement R4 acts as a control to support compliance with requirements R1 & R3. It is in the best interest of the entity to continue to investigate and detect whether its Protection System components caused a mis-operation and develop a corrective plan for the identified Protection System component. This can be achieved through the entity's internal control policies and procedures engineered to maximize efficiency and reliability. Entities endeavor to determine the cause of a Misoperation and doing so may take extended time if equipment outages are necessary. However, if an entity is unable to determine the cause, further investigation(s) using the same event data are unlikely to lead to identification of the cause. Proposed retirement of R4 does not preclude the entity's responsibility to continue the investigation to identify the cause of mis-operation. However, it does alleviate the need to keep tracking documents for the sake of showing investigative actions.

PRC-015-1 R1, R2, R3 (All) (LT)
PRC-015-1 will be retired as it will be superseded by PRC-012-2. R1 requires the applicable entities to maintain a list of RAS which is an administrative requirement that does not contribute to the reliability of the BES. R2 references PRC-012-1 R1 which is not enforceable and will be superseded by PRC-012-2. Requirement R3 will be superseded by PRC-012-2. In support of the Independent Expert Review Panel's (IERP) justification to retire the standard: "P81 Administrative/Documentation", this is an administrative requirement. RE and NERC already have authority to request such information.

PRC-018-1 R1, R2, R3, R4, R5, R6 (All) (LT)
This standard requires both the TO or GO to ensure that DME's installed per PRC-002-1 and meet specific criteria. PRC-002-1 was never approved by FERC but PRC-018 was approved on the basis that each RRO would establish a DME program and that even if PRC-002-1 were not approved; PRC-018 could be enforced per the RRO program. Most RRO's have retired their programs which establish the scope of DME's for this standard. Furthermore, there are differences in the methodologies used by the RRO's to establish scope of DME's and what is mandated by requirement R1 of PRC-002-2. The lists of DME's and where they are installed will differ from PRC-018-1 and PRC-002-2.

TOP-001-4 R16, R17 (OP)
These requirements can be retired because the authority to approve or deny outages of any equipment, whether load carrying or not, is a fundamental attribute of the system operator role. This was recognized by NERC and FERC in Project 2007-03 where the authority language in former Standard TOP-001-1 R1 was removed from the revised TOP standards approved by both NERC and FERC.

TOP-001-4 R19 (OP)
The requirement is a control for aiding compliance with TOP-002-4 R1 related to the performance of an Operational Planning Analysis (OPA) and it is duplicative to requirements R5 in TOP-003-3. Standard TOP-003-3 requires the TOP to identify the data it needs to perform its OPA (R1), which entities need to provide such data (R3), and then obligates those registered entities to then supply the data (R5). For an entity to fulfill TOP-003-3 R5, it must be able to exchange data with the requesting TOP. Additionally, to comply with TOP-002-4 R1, the TOP must have received all of the data it needs to perform the OPA.

TOP-001-4 R22 (OP)
The requirement is a control for aiding compliance with TOP-002-4 R4 related to preparing Operating Plans and it is duplicative to requirement R5 in TOP-003-3. Standard TOP-003-3 requires the BA to identify the data it needs to perform its analysis functions (R2), which entities need to provide such data (R4), and then obligates those registered entities to then supply the data (R5). For an entity to fulfill TOP-003-3 R5, it must be able to exchange data with the requesting BA. Additionally, to comply with TOP-002-4 R4, the BA must have received all of the data it needs to perform its analysis functions.

VAR-001-4.2 R2 (OP)
This requirement is duplicative of other SOL requirements. R2 is related to maintaining the system within SOLs because a voltage limit is a form of SOL. TOP-002-4 already requires TOPs to identify where the potential SOL exceedances might occur for next-day operations and prepare a plan to mitigate these potential SOL exceedances, including notifying entities of their role in those plans (R3). When moving into real-time operations, the requirements of TOP-001-4 govern and the TOP continues to be obligated to operate within SOLs and direct the operation of the system to operate within SOLs or return to operation within SOLs (R12 and R14). R1 of TOP-001-4 requires the TOP to act and direct action to maintain reliability, including obtaining necessary reactive resources as described in VAR-001-4.2 R2.

VAR-001-4.2 R3 (OP)
This requirement is duplicative of TOP-001-4 requirements:

- TOP-001-4 R1, which states that the TOP "shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions." The requirement to "act" using all available actions, whether by "its own actions" or by the actions of others via "issuing

Operating Instructions" is the same as VAR-001-4.2 R3 to "operate or direct ... operation of devices to regulate ... voltage and reactive flow."

- The purpose of the actions taken under VAR-001-4.2, R3 is the same purpose accomplished by TOP-001-4 R1, R10, R12, R13 and R14 by acting to operate within limits (SOLs and IROLs) to maintain reliability of its transmission system.

VAR-001-4.2 E.A.15 (RT)
This is a Regional variance requirement applicable to WECC only. The continent-wide requirement VAR-002-4.1 R2.3 addresses the same reliability objective.

Additionally, the following Standards and Requirements were consolidated into MOD-001-2 in project 2012-05, which was filed for regulatory approval on February 10, 2014, and is still pending approval.

MOD-001-1a R1, R2, R3, R4, R5, R6, R7, R8, R9 (OP)
MOD-004-1 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12 (OP)
MOD-008-1 R1, R2, R3, R4, R5 (OP)
MOD-028-2 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11 (OP)
MOD-029-2a R1, R2, R3, R4, R5, R6, R7, R8 (OP)
MOD-030-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10 (OP)

The February 10, 2014 petition notes that ATC/AFC are commercially-based values used to facilitate a market for unused transmission capacity in an open access environment and that the values do not directly control the operation of the BPS. It further acknowledges that TOPs are ultimately responsible for operating the grid in a reliable manner consistent with System Operating Limits, not ATC/AFC values. Nevertheless, the filing proposes MOD-001-2 for approval by FERC indicating ATC/AFC values have the potential to influence Real-time conditions on the Bulk-Power System and impact Real-time operations. Although, ATC/AFC values may have the potential to influence Real-Time conditions, there are a number of approved Reliability Standards that address potential impacts to Real-time operations and operation of the grid in a reliable manner consistent with System Operation Limits. This includes TOP Reliability Standard improvements that have been filed and approved since the MOD-001-2 filing in February 2014. NAESB may further address market issues associated with ATC/AFC, however these commercially-based values and market related issues should not be addressed through NERC Reliability standards.

Therefore, we recommend that NERC withdraw the February 10, 2014 petition related to MOD-001-2 and proceed with the retirement of the above listed MOD standards.

Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The team did not identify any known cost impacts.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.* Dispersed Generation Resources):

No unique characteristics of the BES facilities that may be impacted by this proposal were identified by the SER team.
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):
All.
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.
SER Project Team(s)
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 identified by the SER team.
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.
☒	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

[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.

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 identified.

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

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%			
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%			

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
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%			
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%			

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
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%			
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%			

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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%			
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%			

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
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		
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		

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
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		
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		

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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		
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%			

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
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		
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%			

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
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		
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%			

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
334	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.40% Approval: 52.72%			
335	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 77.94% Approval: 64.24%			
336	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.06% Approval: 68.93%			
337	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.51% Approval: 63.63%			
338	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 78.59%	Support 10/4/12		
339	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 92.75%	Support 10/4/12		
340	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 89.73%	Support 10/4/12		
341	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 93.73%	Support 10/4/12		
342	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.53%	Support 10/4/12		
343	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 91.79%	Support 10/4/12		
344	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.47%	Support 10/4/12		
345	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 94.60%	Support 10/4/12		
346	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 88.99%	Support 10/4/12		
347	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.67%	Support 10/4/12		
348	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation Plan	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 94.91%	Support 10/4/12		
349	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 93.23%	Support 10/4/12		
350	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Recirculation Ballot	10/24/2012	11/5/2012	Quorum: 85.14% Approval: 71.39%			
351	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	10/24/2012	11/5/2012	Quorum: 78.93% Approval: 71.04%			
352	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Successive Ballot	10/26/2012	11/6/2012	Quorum: 82.04% Approval: 76.08%	Support 11/5/12		
353	Project 2010-11	Project 2010-11 TPL footnote b Initial Ballot October 2012 in	Initial Ballot	11/9/2012	11/19/2012	Quorum: 80.45% Approval: 56.18%			
354	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Initial Ballot	11/26/2012	12/5/2012	Quorum: 84.81% Approval: 72.57%	Oppose 12/5/12		
355	Project 2013-02	Project 2013-02 - Paragraph 81	Initial Ballot	11/30/2012	12/10/2012	Quorum: 75.77% Approval: 96.45%	Support 12/10/12		
356	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	12/4/2012	12/13/2012	Quorum: 76.78% Approval: 53.57%	No Consensus 12/13/12		
357	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	12/4/2012	12/13/2012	Quorum: 77.22% Approval: 57.91%			
358	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Successive Ballot	12/7/2012	12/17/2012	Quorum: 76.47% Approval: 33.23%	Oppose 12/17/12		
359	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	12/7/2012	12/17/2012	Quorum: 75.58% Approval: 34.80%			
360	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Initial Ballot	12/11/2012	12/20/2012	Quorum: 84.50% Approval: 95.60%	Support 12/19/12		
361	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Successive Ballot	12/11/2012	12/20/2012	Quorum: 83.24% Approval: 84.48%	Support 12/19/12		
362	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.89% Approval: 73.06%			
363	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 79.00% Approval: 79.36%			
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		

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
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		
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%			

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
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: %			
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%			

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
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.
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%			

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
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%			
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%			

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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	
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	

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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		
476	Project 2012-13	Project 2012-13 - NUC - Nuclear Plant Interface Coordination	Initial Ballot	5/13/2014	5/22/2014	Quorum: 80.60% Approval: 97.36%	Support--5/20/14	Affirmative		
477	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays) - PRC-005-X	Initial Ballot	5/23/2014	6/2/2014	Quorum: 85.42% Approval: 47.89%	Support	Affirmative		
478	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Initial Ballot	5/30/2014	6/9/2014	Quorum: 79.06% Approval: 17.02%	Does not Support--6/6/14	Negative		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Final Ballot	6/12/2014	6/23/2014	Quorum: Approval: 89.03%/83.46%	Support	Affirmative		
479	Project 2007-11	Project 2007-11 - Disturbance Monitoring - PRC-002-2	Additional Ballot	6/13/2014	6/23/2014	Quorum: 77.69% Approval: 52.29%	Support	Affirmative	Extended to achieve a quorum.	Last RSC Meeting
480	Project 2010-05.1	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Additional Ballot	6/20/2014	7/9/2014	Quorum: 76.98% Approval: 74.53%	Support	Affirmative	Extended to achieve a quorum.	
481	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Ballot	6/23/2014	7/2/2014	Quorum: 82.32%/82.59%/82.59%/82.85%/82.85%/82.06%/82.59%/82.85%/82.85%/81.00%/80.74% Approval: 68.57%/36.94%/47.87%/60.26%/61.67%/57.94%/30.99%/62.18%/63.07%/62.64%/64.70%	No Consensus--6/24/14	Affirmative Negative Affirmative Affirmative Affirmative Affirmative Negative Affirmative Affirmative		
482	Project 2012-13	Project 2012-13 NUC - Nuclear Plant Interface Coordination	Final Ballot	6/24/2014	7/3/2014	Quorum: 88.63% Approval: 97.23%	Support--6/23/14	Affirmative		
483	Project 2014-02	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions Rich HTML Content 1 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			

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
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% Approval: 76.12%/74.23%/75.67%/85.49%/75.96%/78.67%/48.73%/78.87%/87.03%/93.34%/90.13%	TOP-001-3: Negative TOP-002-4: Affirmative TOP-003-3: Affirmative IRO-001-4: No consensus however the majority indicated an Affirmative vote IRO-002-4: Negative IRO-008-2: No consensus, a majority indicated a Negative and the others indicated abstention IRO-010-2: Affirmative IRO-014-3: Negative IRO-017-1: Affirmative Implementation Plan and Definitions: Affirmative 9/18/14		
493	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	9/23/2014	10/2/2014	Quorum: 79.94% Approval: 46.73%	Negative--10/1/14		
494	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	9/26/2014	10/6/2014	Quorum: 79.01% Approval: 53.02%	Affirmative--10/1/14		
495	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Additional Ballot	9/29/2014	10/8/2014	Quorum: 83.24%/84.82% Approval: 80.69%/84.05%	Affirmative--10/7/14	Affirmative	
496	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	10/1/2014	10/10/2014	Quorum: 82.93% Approval: 57.95%	Affirmative--10/7/14		
497	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Additional Ballot	10/3/2014	10/14/2014	Quorum: 80.54% Approval: 75.79% Approval:	Affirmative--10/7/14		
498	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Additional Ballot	10/7/2014	10/16/2014	Quorum: 81.91%/82.12% Approval: 94.92%/94.37%	Affirmative--10/14/14		
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%	Affirmative--10/17/14		

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						Approval: 82.64%/85.96%/86.22%/94.07%/91.84%	~~Affirmative--10/17/14~~		
502	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards (TOP-002-4, TOP-003-3, IRO-008-2, IRO-014-3, and IRO-017-1)	Final Ballot	10/10/2014	10/20/2014	Quorum: 89.71%/88.39%/89.71%/89.71%/89.97% 84.76%/86.55%/83.73%/89.88%/82.58%	Affirmative--10/17/14		
503	Project 2007-11	Project 2007-11 Disturbance Monitoring	Additional Ballot	10/10/2014	10/21/2014	Quorum: 77..69% Approval: 71.38%	Affirmative--10/17/14		
504	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Additional Ballot	10/10/2014	10/22/2014	Quorum: 85.13%/83.29% Approval: 94.75%/93.98%	Affirmative--10/20/14		
505	Project 2014-03	Project 2007-17.3 (PRC-005-X) Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays)	Final Ballot	10/20/2014	10/29/2014	Quorum: 88.25% Approval: 74.14%	Affirmative--10/28/14		
506	Project 2014-03	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.53% Approval: 83.12%	Affirmative--10/31/14		
507	Project 2007-11	Project 2007-11 Disturbance Monitoring	Final Ballot	10/28/2014	11/6/2014	Quorum: 81.89% Approval: 68.51%	Affirmative--10/31/14		
508	Project 2007-11	Project 2010-05.2 Phase 2 of Special Protection Systems	Final Ballot	10/28/2014	11/6/2014	Quorum: 85.41% Approval: 73.33%	Negative--10/14/14		
509	Project 2007-11	Project 2009-03 Emergency Operations	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.19% Approval: 73.20%	Affirmative--10/17/14		
510	Project 2007-11	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	10/28/2014	11/6/2014	Quorum: 89.49%/87.66%/87.08% Approval: 92.91%/92.15%/95.62%	Affirmative--10/20/14		
511	Project 2014-03	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.56%/87.32%87.07%/87.56%/87.80%87.56%86.59% Approval: 83.84%/95.34%/86.00%/95.35%91.17%/83.88%/95.40%/92.76%	CIP-003-6 no consensus CIP-010-2 no consensus New Definitions-Affirmative Updated Definitions-Affirmative Implementation Plan-Affirmative Version X Materials-Affirmative Non-binding polls-Affirmative		
512	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards	Additional Ballot	11/4/2014	11/10/2014	Quorum: 78.36% Approval: 60.21%	Affirmative--11/4/14		
513	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	11/12/2014	11/21/2014	Quorum: 79.73% Approval: 77.29%	Affirmative--11/21/14		
514	Project 2014-03	Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	11/14/2014	11/24/2014	Quorum: 79.83% Approval: 67.39%	Affirmative--10/1/14		
515	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	12/5/2014	12/16/2014	Quorum: 84.27% Approval: 78.05%	Affirmative--12/12/14		
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		

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522	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-001-1.1(ii), PRC-019-2, and PRC-024-2	Final Ballots	1/13/2015	1/22/2015	Quorum: 89.27%/89.30%/89.52 % Approval: 93.99%/94.03%/95.82 %	Affirmative--1/22/15		
523	Project 2014-02	2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions CIP-003-7, CIP-004-7, CIP-010-3, and CIP-011-3	Final Ballot	1/23/2015	2/2/2015	Quorum: 84.15%/84.39%/84.15 %/84.39%/84.39%/83. 90%/84.39%/83.66% Approval: 79.76%/98.94%/98.94 %/86.76%/98.93%/84. 07%/90.10%/97.32%	Affirmative--1/29/15		
524	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-5	Final Ballot	3/2/2015	3/11/2015	Quorum: 83.52% Approval: 98.03%	Affirmative--1/22/15		
525	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	3/6/2015	3/16/2015	Quorum: 77.29% Approval: 59.30%	Negative--3/13/2015		
526	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations	Initial Ballot	3/27/2015	4/7/2015	Quorum: 79.93% Approval: 84.31%	Affirmative--3/31/15		
527	Project 2014-04	Project 2014-04 Physical Security	Initial Ballot	3/31/2015	4/9/2015	Quorum: 88.33% Approval: 89.95%	Affirmative--3/31/15		
528	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations	Final Ballot	4/17/2015	4/27/2015	Quorum: 84.86% Approval: 89.63%	Affirmative--3/31/15		
529	Project 2014-04	Project 2014-04 Physical Security	Final Ballot	4/20/2015	4/29/2015	Quorum: 92.00% Approval: 92.35%	Affirmative--3/31/15		
530	Project 2007-06	Project 2007-06 System Protection Coordination	Additional Ballot	5/6/2015	5/15/2015	Quorum: 81.79% Approval: 39.63%	Negative--5//13/15		
531	Project 2015-06	2015-06 Interconnection Reliability Operations and Coordination	Initial Ballot	6/29/2015	7/8/2015	Quorum: 75.23%/84.00% Approval: 90.35%/97.50%	Affirmative--7/7/15		
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%	Affirmative--9/11/15		

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						Approval: 62.55%	~~Affirmative--9/11/15~~		
537	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005 and BAL-006	Initial Ballot	9/4/2015	9/14/2015	Quorum: 83.81% Approval: 55.97%	Abstention--9/14/15		
538	Project 2015-04	2015-04 Alignment of Terms	Final Ballot	9/4/2015	9/14/2015	Quorum: 96.81%/97.53%/97.51%/97.48%/97.51%/97.53%/97.53%/97.11%/97.11%/97.85%/96.80%/97.12%/97.14%/97.14%/97.14%/97.11%/97.14%/96.80%/97.11%/97.48%/97.85%/97.48%/97.48%/97.48%/97.48%/97.48% Approval: 93.13%/92.89%/91.33%/98.07%/98.07%/84.78%/84.75%/98.30%/98.06%/75.63%/95.46%/94.48%/98.31%/97.11%/98.57%/90.80%/95.60%/90.46%/92.07%/92.49%/97.81%/92.84%/91.09%/91.32%/90.80%/98.29%	Affirmative--7/24/15		
539	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	Initial Ballot	9/4/2015	9/16/2015	Quorum: 86.97% Approval: 96.73%	Affirmative--9/16/15		
540	Project 2010-04.1	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	Initial Ballot	9/9/2015	9/18/2015	Quorum: 85.57% 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		

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554	Project 2010-07.1	Project 2010-07.1 Vegetation Management	Final Ballot	1/29/2016	2/8/2016	Quorum:90.03% Approval: 96.18%	Affirmative--2/1/16		
552	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005 and BAL-006	Final Ballot	1/29/2016	2/8/2016	Quorum: 86.35%/86.98%/86.67 % Approval: 72.06%/94.61%/80.15 %	Affirmative--2/3/15		
551	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Final Ballot	2/17/2016	2/26/2016	Quorum: 88.36%/87.79% Approval: 75.68%/73.87%	Affirmative--1/25/16		
552	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Additional Ballot	3/9/2016	3/18/2016	Quorum: 75.55% Approval: 78.87%	Affirmative--3/10/16		
553	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Initial Ballot	4/15/2016	4/25/2016	Quorum: 83.39%/83.33% Approval: 80.57%/78..39%	Affirmative--4/20/16		
554	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Final Ballot	4/20/2016	4/29/2016	Quorum: 81.19%/87.15% 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		

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569	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7 and Implementation	Final Ballot	12/9/2016	12/19/2016	Quorum: 82.89%/83.14% Approval: 87.95%/83.03%	Affirmative--12/1/16		
570	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Additional Ballot	12/28/2016	1/6/2017	Quorum: 79.47% Approval: 93.55%	Affirmative--1/4/17		
571	Project 2015-08	Project 2015-08 Emergency Operations EOP-005-3, EOP-006-3	Final Ballot	12/28/2016	1/6/2017	Quorum: 91.00%/91.55% Approval: 83.65%/80.56%	Affirmative--1/4/17		
572	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7(i) Implementation Plan and 2 Definitions	Initial Ballot	1/16/2017	1/25/2017	Quorum: 77.81%/76.71%/77.26%/76.71% 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%	Affirmative--3/2/18		

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
						Approval: 96.64%/97.88%	~~Affirmative--5/2/18~~		
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		
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		
604	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		

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Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments

RSC Meeting #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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 #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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

RSC Meeting #18-5, Agenda Item 6.3: Comment History

(As of 12/4/2018)

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."

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
Regional Standards Committee approved Regional Standard Authorization Request (RSAR) for posting	June 23, 2015

Anticipated Actions	Date
1st 45-day Formal Comment Period	September 1, 2017 - October 18, 2017
2nd 45-day Formal Comment Period	April 16, 2018 – June 1, 2018
30-day Pre-ballot Period	
10-day ballot Period	
Board adoption	

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

A. Introduction

1. **Title:** Automatic Underfrequency Load Shedding
2. **Number:** PRC-006-NPCC-2
3. **Purpose:** The NPCC Automatic Underfrequency Load Shedding (UFLS) regional Reliability Standard establishes more stringent and specific NPCC UFLS program requirements than the NERC continent-wide PRC-006 standard. The program is designed such that declining frequency is arrested and recovered in accordance with established NPCC performance requirements stipulated in this document.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Generator Owner
     - **4.1.2.** Planning Coordinator
     - **4.1.3.** Distribution Providers that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators
     - **4.1.4.** Transmission Owners that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators
5. **Effective Date:** See Implementation Plan.

B. Requirements and Measures

Rationale for Requirement R1: Figure 1 of this document shows the NPCC underfrequency criteria for the Eastern Interconnection portion of NPCC. Figure 1 also shows the NERC criteria as defined in the NERC PRC Standard on UFLS.

R1. Each Planning Coordinator in the Eastern Interconnection portion of NPCC shall design an UFLS program, pertaining to islands wholly within the NPCC Region, having performance characteristics that prevents the frequency from remaining below 59.5 Hz for more than 30 seconds in accordance with Figure 1 *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M1. Each Planning Coordinator shall have evidence such as reports, system studies and/or real-time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

R2. Each Planning Coordinator shall provide UFLS island boundaries, as identified per the NERC continent-wide PRC-006 Standard on UFLS, to Distribution Providers, Generator Owners, and Transmission Owners within 30 calendar days of receipt of a request. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

R3. Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program, reflecting normal operating conditions, excluding outages. The automatic UFLS program shall be implemented on an island basis for each identified island per the NERC continent-wide PRC-006 Standard on UFLS as follows: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

- The UFLS program shall be implemented by each Distribution Provider and Transmission Owner according to the frequency thresholds, nominal operating times, and load shedding amounts specified in Attachment C, Tables 1-3; or
- The UFLS program shall be implemented collectively by multiple Distribution Providers or Transmission Owners, as long as they reside in the same UFLS island identified by the Planning Coordinator per Requirement R2. These multiple Distribution Providers or Transmission Owners, via mutual agreement, shall act as a single entity to provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load according to the frequency thresholds, total nominal operating time, and load shedding amounts specified in Attachment C, Tables 1-3.

M3. Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped in their respective areas, and the corresponding frequency thresholds, on those circuits included in its UFLS program identified in Requirement R3. (Attachment C, Tables 1-3).

R4. Each Distribution Provider or Transmission Owner in the Eastern Interconnection portion of NPCC that does not meet the UFLS program parameters specified in Attachment C, Table 1-3, and each Distribution Provider or Transmission Owner in the Quebec Interconnection that does not meet the UFLS program parameters specified by its Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

- Within 30 calendar days of determining that it does not meet the specified parameters, notify its Planning Coordinator that it does not meet the UFLS program parameters; and
- Within the following 180 calendar days from notification of the Planning Coordinator,

(1) develop a Corrective Action Plan and a schedule for implementation that is mutually agreed upon with its Planning Coordinator or
(2) provide its Planning Coordinator with a technical study that demonstrates that the deviations from the program parameters will not result in failure of UFLS performance criteria being met for any island. The technical study must be acceptable to the Planning Coordinator prior to implementing deviations from program parameters and shall demonstrate coordination with UFLS programs of all entities residing within the same island(s) identified by the Planning Coordinator in Requirement R2. The technical study shall also demonstrate coordination with other UFLS programs of adjoining Planning Coordinators, or
(3) provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3.

M4. Each Distribution Provider or Transmission Owner shall have evidence such as reports analysis, system studies and dated documentation that demonstrates that it meets Requirement R4.

Rationale for Requirement R5: An inhibit function provides supervisory control over a UFLS relay. For example, an undervoltage inhibit feature prevents UFLS relay operation if the sensed voltage decreases below an adjustable setting. An undervoltage inhibit function is intended to prevent operation of a UFLS relay when the transmission supply is lost to distribution station feeding many induction motors. Following loss of the transmission supply, motors may support the voltage while the motors coast down in speed. The motors coasting down (ringing down) will look like an underfrequency event to the relay. The inhibit setting is set to a voltage above which the motor load is expected to sustain. This prevents the underfrequency relay from tripping and locking out distribution feeder breakers supplying the motor load, between the time the transmission supply line trips and the time when the line recloses to restore the load. Voltages sustained by motors that are coasting down (e.g. 0.70 pu) are typically much lower than voltages at which the UFLS relays are required to operate to meet UFLS performance criteria. However, motor loads supplied by cable networks typically have higher ring down voltages because of cable charging. Therefore, care must be taken so that the voltage inhibit setting is not higher than the voltage at which UFLS relays are required to operate to meet UFLS performance criteria.

R5. Each Planning Coordinator shall develop and review settings for inhibit thresholds at least once per five calendar years (such as, but not limited to, voltage, current and time) to be utilized within its region's UFLS program. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M5. Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R5.

R6. Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 calendar days of any changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Each Planning Coordinator shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R6.

R7. Each Distribution Provider and Transmission Owner that receives a notification pursuant to Requirement R6 shall develop and submit an implementation plan with respect to inhibit thresholds for approval by the Planning Coordinator within 90 calendar days of the request from the Planning Coordinator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R7.

R8. Each Distribution Provider and Transmission Owner shall implement the inhibit thresholds provided by the Planning Coordinator in accordance with Requirement R6 and based on the Planning Coordinator approved implementation plan in accordance with R7. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M8. Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets, completed work orders, or other documentation that demonstrates that it meets Requirement R8.

Rationale for Requirement R9: Ideally, the amount of load to be shed in each stage of the UFLS program for every entity should perfectly match that prescribed in this Standard, for all phases of the load cycle, i.e., seasonal (summer vs. winter), weekly (weekday vs. weekend vs. holidays), daily (morning, noon, and night), etc. for all of the identified islands. Practically, however, this is obviously not possible because the load cycles of the various areas and sub-areas within any given island do not perfectly track the load cycle of the overall island. The UFLS program, on the other hand, is designed based on peak conditions for the overall island. The percentages of actual load shedding that would occur for any conditions other than peak, therefore, can only approximate that prescribed in the Standard. To that end, Requirement R11 requires entities to document measured loads in the UFLS program coincident with their own annual peak, whether or not that peak occurs at the same time or in the same season as the peak of the identified island in which their load resides. Using individual entity peaks vs. overall island peaks provides a consistent approach for accounting purposes among the very entities that are responsible for designing and maintaining their UFLS programs.

R9. Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 calendar months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage. The actual net Load shall be coincident with the entity's integrated hourly peak net Load during the previous year, as determined by measuring or calculating Load through the switches that would disconnect load if triggered by the UFLS relays. If measured data is unavailable then calculated data may be used. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M9. Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the net amount of load shed and the percentage of its peak load at each stage of its UFLS program to demonstrate that it meets Requirement R9.

R10. Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, on or below the appropriate generator underfrequency trip protection setting threshold curve in Figure 2, except as otherwise exempted in Requirements R13 and R16. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M10. Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R10.

R11. Each Generator Owner shall transmit the generator underfrequency trip setting and time delay within 45 calendar days of the Planning Coordinator's request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M11. Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R11.

R12. Each Generator Owner with a new generating unit, or an existing generator increasing its net capability by greater than 10% shall: *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

- **12.1** Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 2.
- **12.2** Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection setting threshold curve in Figure 2.

M12. Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R12.

R13. For existing non-nuclear units in service prior to July 1, 2015, that have underfrequency protections set to trip above the appropriate curve in Figure 2: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

13.1 Each Generator Owner shall set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

13.2 Each Generator Owner shall transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

13.3 Each Planning Coordinator in Ontario, Québec and the Maritime Provinces shall arrange for compensatory load shedding, in accordance with Attachment A and as provided by a Distribution Provider or Transmission Owner, that is adequate to compensate for the loss of generator(s) due to early tripping that is within the UFLS island identified by the Planning Coordinator in Requirement R2.

13.4 Each Generator Owner in the ISO-NE Planning Coordinator area and in NYISO Planning Coordinator area shall arrange for compensatory load shedding, in accordance with Attachment B and as provided by a Distribution Provider or Transmission Owner, that is adequate to compensate for the loss of generator(s) due to early tripping that is within the UFLS island identified by the Planning Coordinator in Requirement R2.

M13. Each Generator Owner with existing non-nuclear units in service prior to July 1, 2015 which have underfrequency tripping that is not compliant with Requirement R10 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R13.

R14. Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R13.3 for generating units in its respective NPCC area. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M14. Each Planning Coordinator in Ontario, Quebec and Maritime provinces shall provide evidence such as reports, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R14.

R15. Each Generator Owner, Distribution Provider or Transmission Owner within the ISO-NE Planning Coordinator area and in NYISO Planning Coordinator Area shall apply the criteria described in Attachment B to determine the compensatory load shedding that

is required in Requirement R13.4 for generating units in its respective NPCC area. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M15. Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the NYISO shall provide evidence such as reports, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R15.

R16. Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 2 based on their licensing design shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

16.1 Set the underfrequency protection to operate at ~~as~~ a ~~low~~ frequency setting that is as low as possible in accordance with the plant design and licensing limitations but not greater than 57.8 Hz.

16.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.

16.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

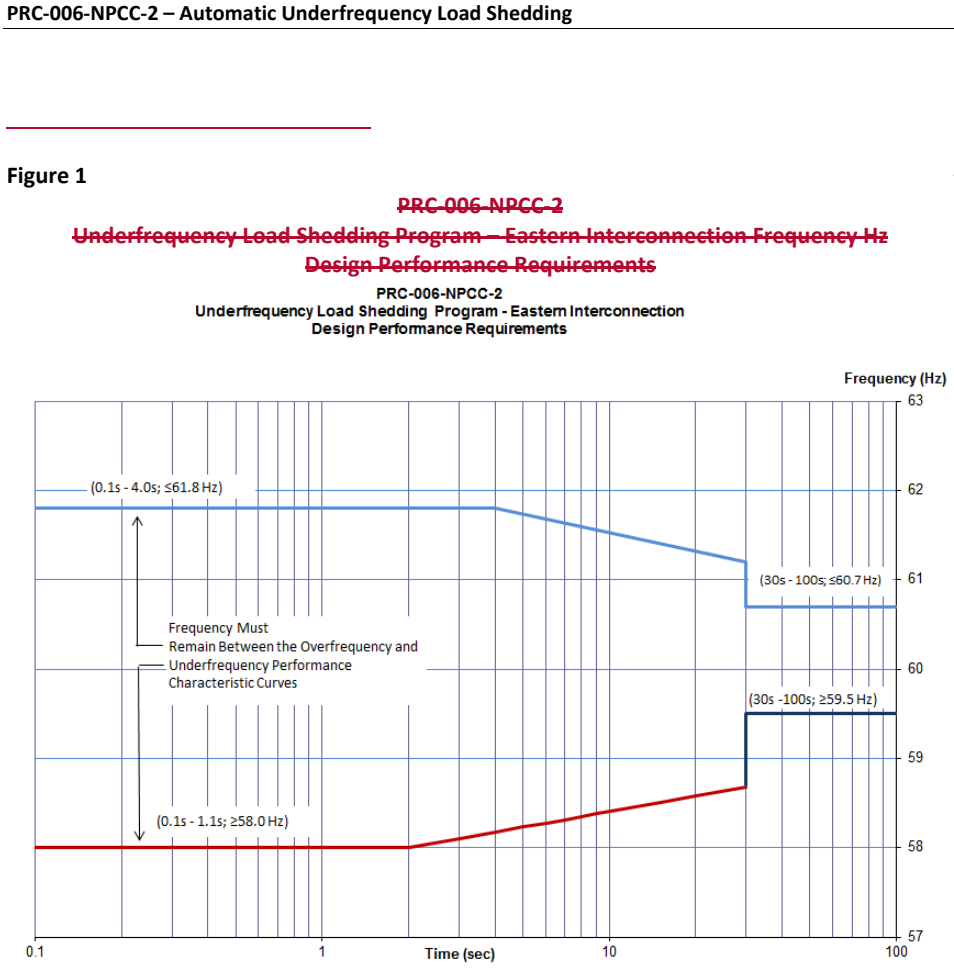
M16. Each Generator Owner of nuclear units that have generator trip settings above the generator trip curve in Figure 2 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R16.

Figure 1

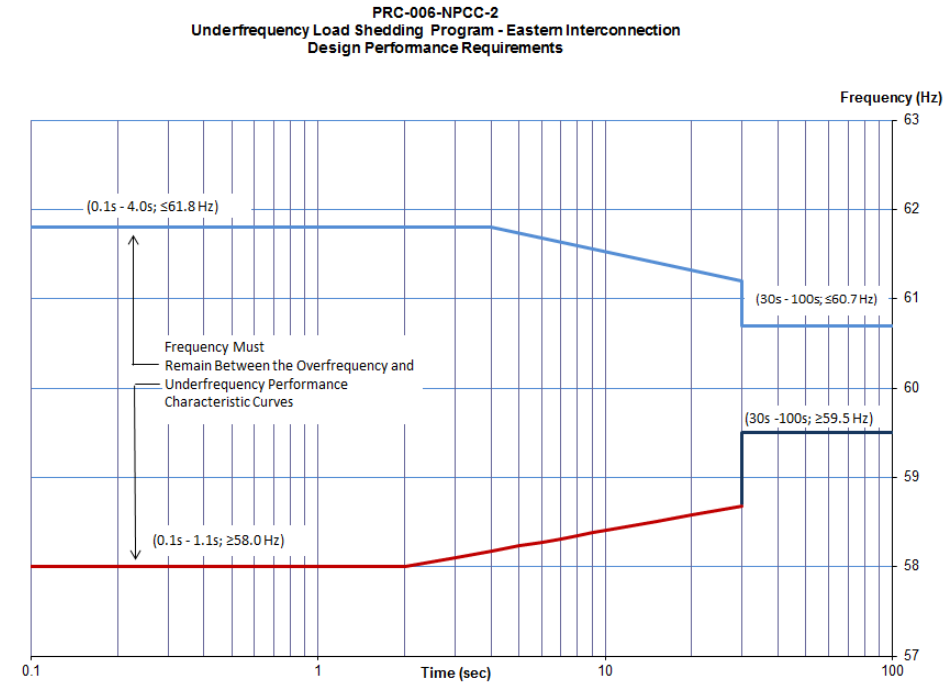
~~PRC-006-NPCC-2~~

~~Underfrequency Load Shedding Program – Eastern Interconnection Frequency Hz~~

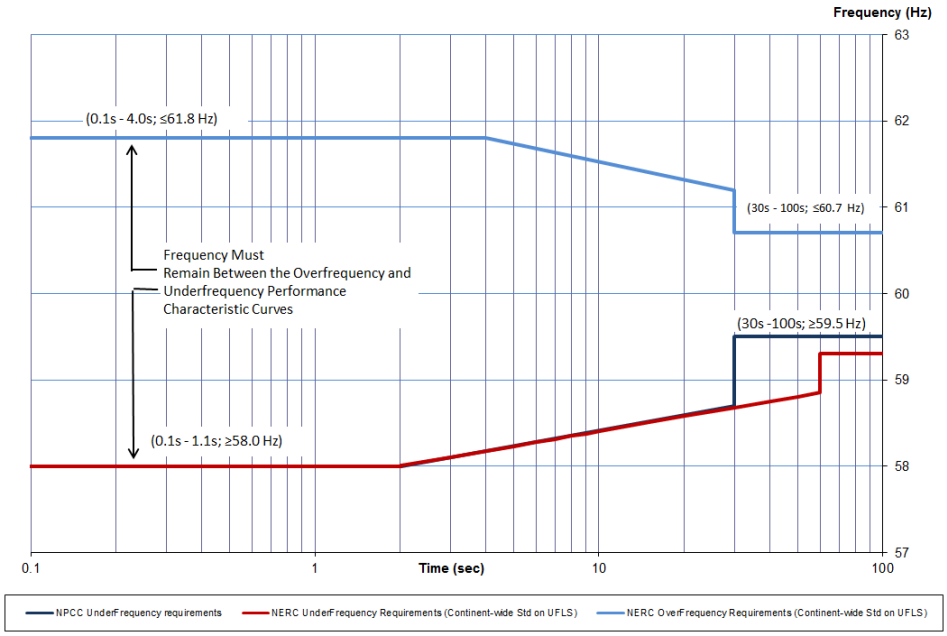
~~Design Performance Requirements~~

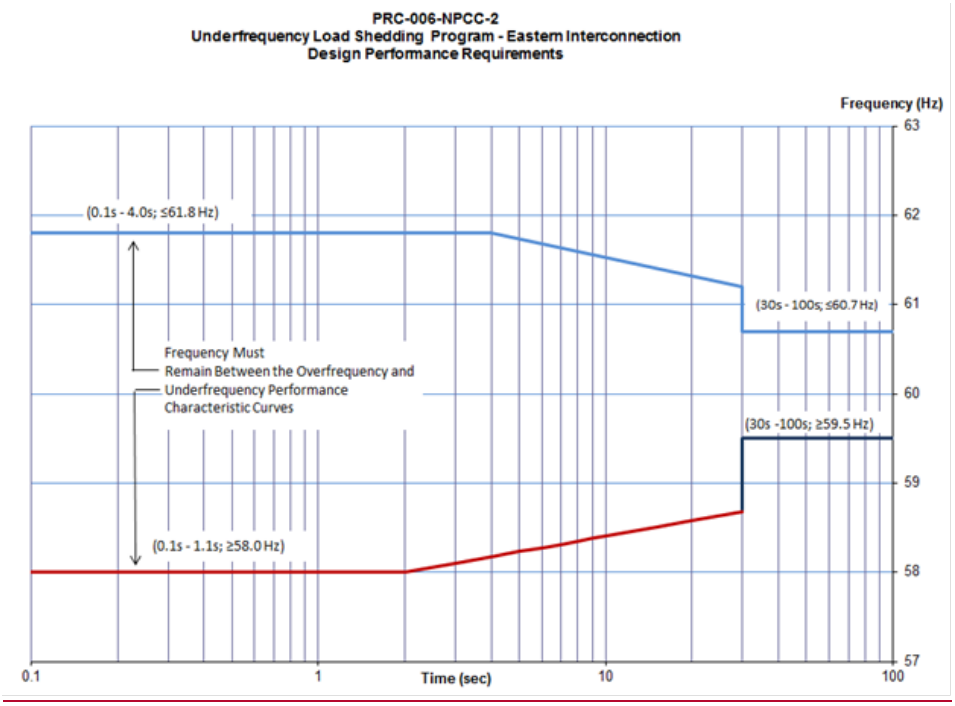


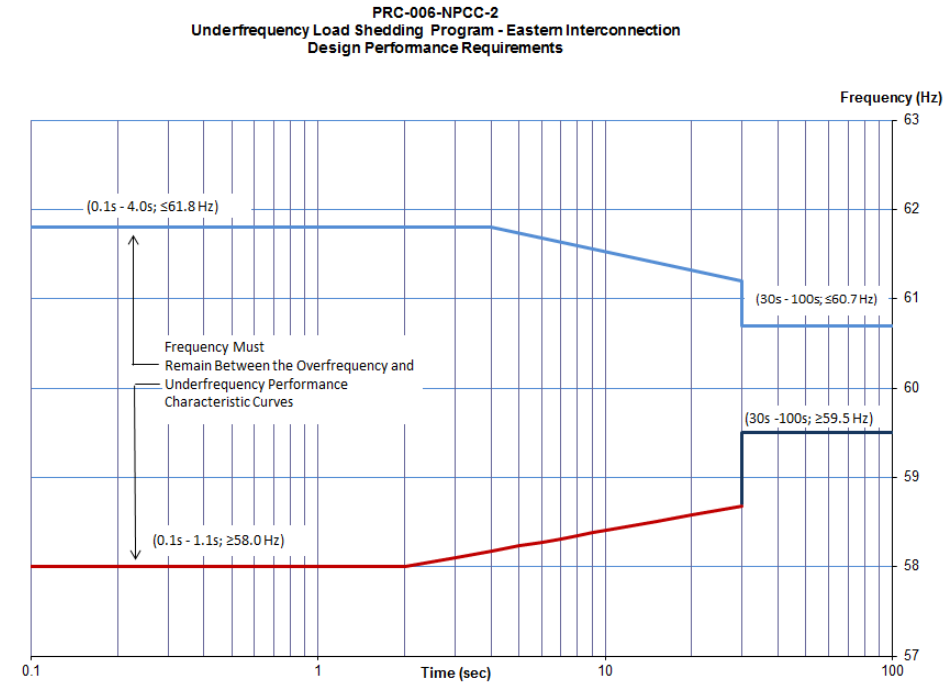
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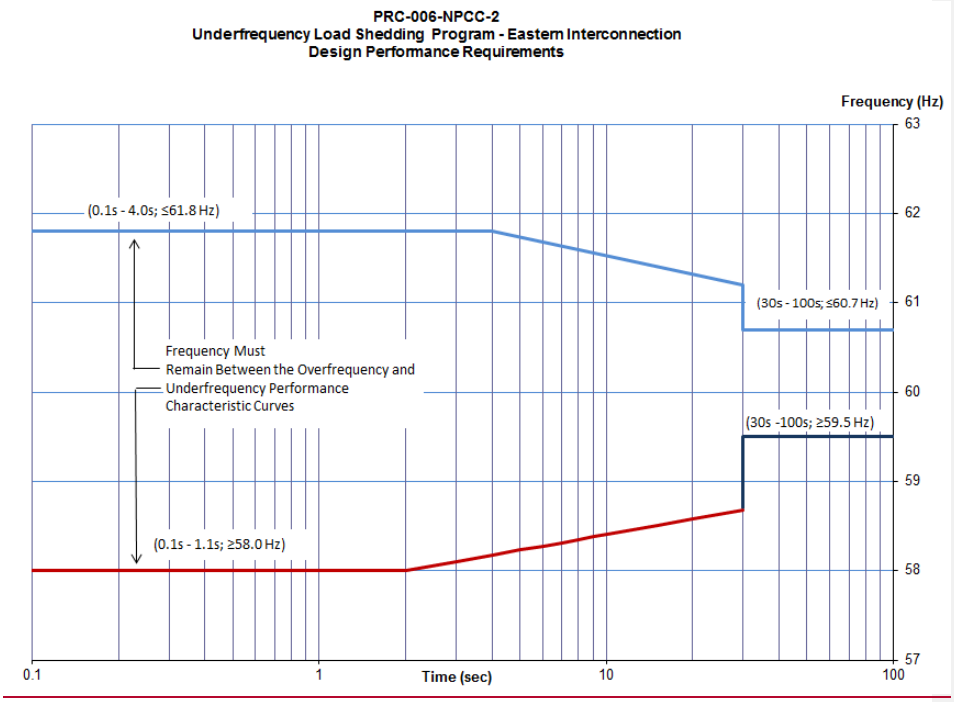

PRC-006-NPCC-2
Underfrequency Load Shedding Program - Eastern Interconnection
Design Performance Requirements
Frequency (Hz)
63
62
61
60
59
58
57
(0.1s - 4.0s; ≤61.8 Hz)
(30s - 100s; ≤60.7 Hz)
Frequency Must
Remain Between the Overfrequency and
Underfrequency Performance
Characteristic Curves
(30s -100s; ≥59.5 Hz)
(0.1s - 1.1s; ≥58.0 Hz)
0.1
1
10
100
Time (sec)

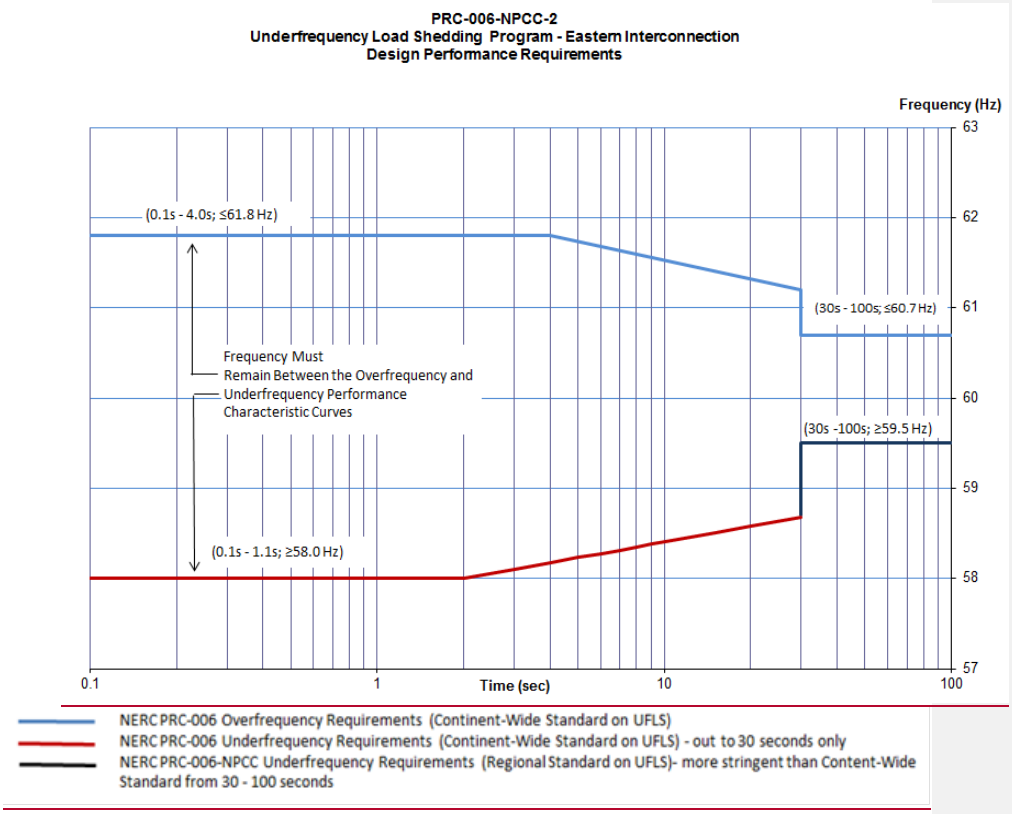
PRC-006-NPCC-2 Figure 1
Underfrequency Load Shedding Program - Eastern Interconnection
Design Performance Requirements




PRC-006-NPCC-2
Underfrequency Load Shedding Program - Eastern Interconnection
Design Performance Requirements
Frequency (Hz)
63
62
61
60
59
58
57
(0.1s - 4.0s; ≤61.8 Hz)
(30s - 100s; ≤60.7 Hz)
Frequency Must
Remain Between the Overfrequency and
Underfrequency Performance
Characteristic Curves
(30s -100s; ≥59.5 Hz)
(0.1s - 1.1s; ≥58.0 Hz)
0.1
1
Time (sec)
10
100


PRC-006-NPCC-2
Underfrequency Load Shedding Program - Eastern Interconnection
Design Performance Requirements
Frequency (Hz)
63
62
61
60
59
58
57
(0.1s - 4.0s; ≤61.8 Hz)
(30s - 100s; ≤60.7 Hz)
Frequency Must
Remain Between the Overfrequency and
Underfrequency Performance
Characteristic Curves
(30s -100s; ≥59.5 Hz)
(0.1s - 1.1s; ≥58.0 Hz)
0.1
1
10
100
Time (sec)


PRC-006-NPCC-2
Underfrequency Load Shedding Program - Eastern Interconnection
Design Performance Requirements
Frequency (Hz)
63
62
61
60
59
58
57
(0.1s - 4.0s; ≤61.8 Hz)
(30s - 100s; ≤60.7 Hz)
Frequency Must
Remain Between the Overfrequency and
Underfrequency Performance
Characteristic Curves
(30s -100s; ≥59.5 Hz)
(0.1s - 1.1s; ≥58.0 Hz)
0.1
1
10
100
Time (sec)



Curve Data:

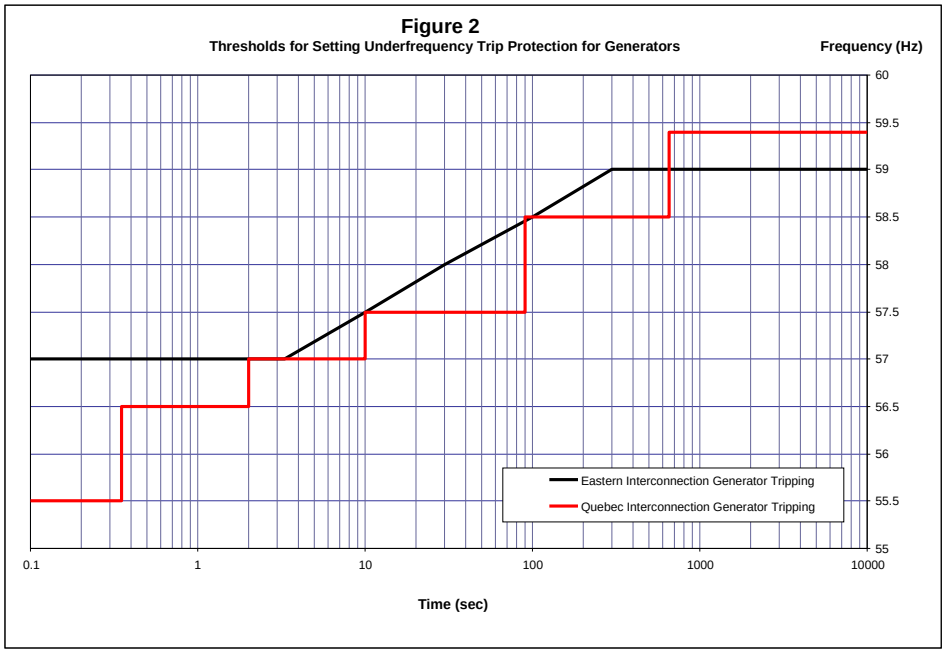
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Overfrequency Requirements		Source
t ≤ 4 s	f = 61.8 Hz	NERC PRC-006 (Continent-Wide Standard on UFLS)
4 s < t ≤ 30 s	f = -0.686log(t) + 62.21 Hz	
t > 30 s	f = 60.7 Hz	

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Underfrequency Requirements		Source
t ≤ 2 s	f = 58.0 Hz	NERC PRC-006 (Continent-Wide Standard on UFLS)
2 s < t ≤ 30 s	f = 0.575log(t) + 57.83 Hz	
t > 30 s	f = 59.5 Hz	NERC PRC-006-NPCC (Regional Standard on UFLS)

Figure 2
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Thresholds for Setting Underfrequency Trip Protection for Generators



C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
Northeast Power Coordinating Council

1.2. Evidence Retention:

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 2, 3, 4, 5, 8, and 9.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 5, 6, and 7.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 15.

The Generator Owner shall keep evidence for three calendar years for Measures 10, 11, 12, 13, and 16.

1.3. Compliance Monitoring and Enforcement Program:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

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 failed to design an UFLS program having performance characteristics that prevent frequency from remaining below 59.5 Hz in accordance with Figure 1.
R2.	The Planning Coordinator provided its UFLS island boundaries, as identified per the NERC ~~continent wide~~continent-wide PRC-006 Standard on UFLS but did so more than 30 calendar days and up to and including 40 days following a request.	The Planning Coordinator provided its UFLS island boundaries, as identified per the NERC ~~continent wide~~continent-wide PRC-006 Standard on UFLS but did so more than 40 calendar days but less than and including 50 days following a request.	The Planning Coordinator provided its UFLS island boundaries, as identified per the NERC ~~continent wide~~continent-wide PRC-006 Standard on UFLS but did so more than 50 calendar days but less than and including 60 days following a request.	The Planning Coordinator failed to provide its UFLS island boundaries, as identified per the NERC ~~continent wide~~continent-wide PRC-006 Standard on UFLS. within 60 calendar days following a request.
R3.	The Distribution Provider or Transmission Owner failed to apply appropriate settings on 20% or less of the relays identified as included in the UFLS program, or amount of load tripped is within 10% deviation from the required amount of Load required to be shed at each stage	The Distribution Provider or Transmission Owner failed to apply appropriate settings on 20%-40% of the relays identified as included in the UFLS program, or amount of load tripped is within 20% deviation from the required amount of Load required to be shed at each stage m	The Distribution Provider or Transmission Owner failed to apply appropriate settings on 40%-60% of the relays identified as included in the UFLS program, or amount of load tripped is within 30% deviation from the required amount of Load required to be shed at each stage.	The Distribution Provider or Transmission Owner failed to apply appropriate settings on > 60% of the relays identified as included in the UFLS program, or amount of load tripped has a > 30% deviation from the required amount of Load required to be shed at each stage
R4.	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program fulfilled its obligations	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program failed to meet all of items

	Program fulfilled its obligations for Requirement R5, Parts %.1 through Part 5.4 but exceeded the permissible time frame for one or more of the 4 items by a period of up to 10 calendar days but less than or equal to 20 calendar days.	Program fulfilled its obligations for Requirement R5, Parts %.1 through Part 5.4 but exceeded the permissible time frame for one or more of the 4 items within a time greater than 20 calendar days but less than or equal to 30 calendar days.	but exceeded the permissible time frame for one or more of the 4 items within a time greater than 30 calendar days but less than or equal to 60 calendar days.	in Requirement 5 within 60 calendar days of permissible time for each item.
R5.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 100% but more than (and including) 95% of relays within its region's UFLS program.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 95% but more than (and including) 90% of relays within its region's UFLS program.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 90% but more than (and including) 85% of relays within its region's UFLS program.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 85% of relays within its region's UFLS program.
R6.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 calendar days and up to and including 40 calendar days of any changes.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 calendar days but less than and including 50 calendar days of any changes.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 calendar days but less than and including 60 calendar days of any changes.	The Planning Coordinator failed to provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 60 calendar days after any changes
R7.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 calendar days and up to and including 100 calendar days following the request.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 calendar days and up to and including 110 calendar days following the request.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 calendar days and up to and including 120 calendar days following the request.	The Distribution Provider or Transmission Owner failed to develop and submit its implementation plan within 120 days following the request.
R8.	Implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning

	approved implementation plan for less than 100% but more than (and including) 95% of UFLS relays.	Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 95% but more than (and including) 90% of UFLS relays.	Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 90% but more than (and including) 85% of UFLS relays.	Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 85% of UFLS relays.
R9.	The Distribution Provider or Transmission Owner provided to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 more than 15 calendar months but less than (and including) 16 calendar months since last update.	The Distribution Provider or Transmission Owner provided to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 more than 16 calendar months but less than (and including)17 calendar months since last update.	The Distribution Provider or Transmission Owner provided to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 more than 17 calendar months but less than (and including)18 calendar months since last update.	The Distribution Provider or Transmission Owner failed to provide to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 within 18 calendar months since last update.
R10.	N/A	N/A	N/A	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, on or below the appropriate generator underfrequency trip protection settings threshold curve in Figure 2, except as otherwise exempted.
R11.	The Generator Owner transmitted the generator underfrequency trip setting and time delay more than 45calendar days and less than (and including) 55 calendar days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay more than 55 calendar days and less than (and including) 65 calendar days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay more than 65 calendar days and less than (and including) 75 calendar days of the Planning Coordinator's request.	The Generator Owner failed to transmit the generator underfrequency trip setting and time delay within 75 calendar days of the Planning Coordinator's request.

R12.	N/A	N/A	The Generator Owner with a new generating unit, or an existing generator increasing its net capability by greater than 10%: Did not fulfill the obligation of Requirement R12; Part 12.1 OR Did not fulfill the obligation of Requirement R12, Part 12.2.	The Generator Owner with a new generating unit, or an existing generator increasing its net capability by greater than 10%, did not fulfill the obligations of Requirement R12, Part 12.1 and Part 12.2.
R13.	N/A	The Generator Owner failed to transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinatoras specified in Requirement R13, Part 13.2.	The Generator Owner failed to set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations a specified in Requirement 13, Part 13.1	The Planning Coordinator in Ontario, Québec and the Maritime Provinces or the Generator Owner within the ISO-NE and in NYISO Planning Coordinator areas failed to arrange for compensatory load shedding as specified in Requirement R13, Part 13.3.
R14.	N/A	N/A	N/A	The Planning Coordinator did not apply the criteria described in Attachment A to determine the compensatory load shedding that is required.
R15.	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or Transmission Owner did not apply the criteria described in Attachment B to determine the compensatory load shedding that is required.
R16.	N/A	The Generator Owner failed to transmit the initial frequency trip setting and any changes to the setting and the technical basis for	The Generator Owner: Failed to set the underfrequency protection as specified in Requirement R16; Part 16.1	The Generator Owner did not fulfill the obligations of Requirement R16, Part 16.1 and Part 16.2.

		the settings to the Planning Coordinator as specified in Requirement R16, Part 16.3.	OR Failed to set the frequency trip setting upper tolerance as specified in Requirement R16, Part 16.2.	

D. Regional Variances

None.

E. Associated Documents

Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	2-9-2012	Adopted by Board of Trustees	
2	6-23-2015	RSAR Submitted	

Standard Attachments

PRC-006-NPCC-2 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 2. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all UFLS islands in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements as part of its UFLS Assessment based on the NERC PRC Standard on UFLS:

1. The Planning Coordinator shall identify, compile and maintain a list of all existing non-nuclear generating units in their Planning Coordinator area that were in service prior to the effective date of the regional Standard (~~April~~July 1, 2015~~7~~ PRC-006-NPCC-1). The list must indicate generating units, if any, that have their underfrequency protections set to trip above the appropriate curve in Figure 2. Generating Units not appearing on the list as of the effective date of Version 1 of the regional standard, as shown above, must have their Underfrequency protections set to trip on or below the appropriate curve in Figure 2. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator within which the generator may operate to provide compensatory load shedding.

    2.2 In Ontario and in the Maritime provinces, the compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in

addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 2 during an underfrequency event. If the highest frequency at which the subject generator will trip above the appropriate curve in Figure 2 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 2.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-2 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 2 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify, compile, and maintain a list of all of its existing non-nuclear generating units that were in service prior to the effective date of the regional Standard (~~April~~July 1, 201~~57~~ PRC-006-NPCC-1). The list must indicate the Generator Owner's generating units, if any, which have their underfrequency protections set to trip above the appropriate curve in Figure 2. Generating Units not appearing on the list as of the effective date of Version 1 of the regional standard, as shown above, must have their Underfrequency protections set to trip on or below the appropriate curve in Figure 2. The list shall include the following information associated with each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 2, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the same and smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 2, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the same and smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-2 Attachment C

UFLS Table 1: Eastern Interconnection Distribution Providers and Transmission Owners with 100 MW[2] or more of peak net Load shall implement a UFLS program with the following attributes:					
UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.10	0.30	6.5 – 7.5	6.5 – 7.5
2	59.3	0.10	0.30	6.5 – 7.5	13.5 – 14.5
3	59.1	0.10	0.30	6.5 – 7.5	20.5 – 21.5
4	58.9	0.10	0.30	6.5 – 7.5	27.5 – 28.5
5	59.5	0.10	10.0	2 - 3	29.5 – 31.5

UFLS Table 2: Eastern Interconnection Distribution Providers and Transmission Owners with 50 MW[2] or more and less than 100 MW[2] of peak net Load shall implement a UFLS program with the following attributes:					
UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.10	0.30	14 – 25	14 – 25
2	59.1	0.10	0.30	14 – 25	28 – 50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.
2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

UFLS Table 3: Eastern Interconnection Distribution Providers and Transmission Owners with 25 MW[2] or more and less than 50 MW[2] of peak net Load shall implement a UFLS program with the following attributes:					
UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.10	0.30	28 – 50	28 – 50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.
2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

Rationale Box:

Standard PRC-006-3, R4 requires the Planning Coordinator to conduct a UFLS assessment at least once every five years. However, aside from a UFLS islanding event, it does not prescribe other factors or events which could warrant a new UFLS assessment in less than the five years time-frame.
PRC-006-NPCC-01 contained requirements if changes to load distribution impacted UFLS program performance (R21) but did not consider many other factors. The drafting team recommends retiring these requirements (R21, R22, R23) and replacing them with the following guidance.
Significant variations in the following factors could require a Planning Coordinator to conduct a new assessment:

- Changes to the BES that could modify the creation of islands or the severity of events such as new transmission topologies, revised protection schemes or new or revised RAS.
- Unforeseen islanding event
- Real and reactive load distribution (including changes to location of compensatory load shedding)
- Transmission Owner or Distribution Provider's inability to implement the UFLS program within the stated tolerances
- Load characteristics in particular frequency responsive load
- Automatic load restoration
- Generation geographical distribution
- Generator trip settings
- Generation mix in particular non-BES generation that may not be subject to frequency ride-through criteria
- Generator dynamic modeling
- Dynamic VAR device modeling
- HVDC dynamic modeling

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
Regional Standards Committee approved Regional Standard Authorization Request (RSAR) for posting	June 23, 2015

Anticipated Actions	Date
1st 45-day Formal Comment Period	September 1, 2017 - October 18, 2017
2nd 45-day Formal Comment Period	April 16, 2018 – June 1, 2018
30-day Pre-ballot Period	
10-day ballot Period	
Board adoption	

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

A. Introduction

1. **Title:** Automatic Underfrequency Load Shedding

2. **Number:** PRC-006-NPCC-2

3. **Purpose:** The NPCC Automatic Underfrequency Load Shedding (UFLS) regional Reliability Standard establishes more stringent and specific NPCC UFLS program requirements than the NERC continent-wide PRC-006 standard. The program is designed such that declining frequency is arrested and recovered in accordance with established NPCC performance requirements stipulated in this document.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner

   4.1.2. Planning Coordinator

   4.1.3. Distribution Providers that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators

   4.1.4. Transmission Owners that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators

5. **Effective Date:** See Implementation Plan.

B. Requirements and Measures

Rationale for Requirement R1: Figure 1 of this document shows the NPCC underfrequency criteria for the Eastern Interconnection portion of NPCC. Figure 1 also shows the NERC criteria as defined in the NERC PRC Standard on UFLS.

R1. Each Planning Coordinator in the Eastern Interconnection portion of NPCC shall design an UFLS program, pertaining to islands wholly within the NPCC Region, having performance characteristics that prevents the frequency from remaining below 59.5 Hz for more than 30 seconds in accordance with Figure 1 *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M1. Each Planning Coordinator shall have evidence such as reports, system studies and/or real-time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

R2. Each Planning Coordinator shall provide UFLS island boundaries, as identified per the NERC continent-wide PRC-006 Standard on UFLS, to Distribution Providers, Generator Owners, and Transmission Owners within 30 calendar days of receipt of a request. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

R3. Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program, reflecting normal operating conditions, excluding outages. The automatic UFLS program shall be implemented on an island basis for each identified island per the NERC continent-wide PRC-006 Standard on UFLS as follows: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

- The UFLS program shall be implemented by each Distribution Provider and Transmission Owner according to the frequency thresholds, nominal operating times, and load shedding amounts specified in Attachment C, Tables 1-3; or
- The UFLS program shall be implemented collectively by multiple Distribution Providers or Transmission Owners, as long as they reside in the same UFLS island identified by the Planning Coordinator per Requirement R2. These multiple Distribution Providers or Transmission Owners, via mutual agreement, shall act as a single entity to provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load according to the frequency thresholds, total nominal operating time, and load shedding amounts specified in Attachment C, Tables 1-3.

M3. Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped in their respective areas, and the corresponding frequency thresholds, on those circuits included in its UFLS program identified in Requirement R3. (Attachment C, Tables 1-3).

R4. Each Distribution Provider or Transmission Owner in the Eastern Interconnection portion of NPCC that does not meet the UFLS program parameters specified in Attachment C, Table 1-3, and each Distribution Provider or Transmission Owner in the Quebec Interconnection that does not meet the UFLS program parameters specified by its Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

- Within 30 calendar days of determining that it does not meet the specified parameters, notify its Planning Coordinator that it does not meet the UFLS program parameters; and
- Within the following 180 calendar days from notification of the Planning Coordinator,

(1) develop a Corrective Action Plan and a schedule for implementation that is mutually agreed upon with its Planning Coordinator or
(2) provide its Planning Coordinator with a technical study that demonstrates that the deviations from the program parameters will not result in failure of UFLS performance criteria being met for any island. The technical study must be acceptable to the Planning Coordinator prior to implementing deviations from program parameters and shall demonstrate coordination with UFLS programs of all entities residing within the same island(s) identified by the Planning Coordinator in Requirement R2. The technical study shall also demonstrate coordination with other UFLS programs of adjoining Planning Coordinators, or
(3) provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3.

M4. Each Distribution Provider or Transmission Owner shall have evidence such as reports analysis, system studies and dated documentation that demonstrates that it meets Requirement R4.

Rationale for Requirement R5: An inhibit function provides supervisory control over a UFLS relay. For example, an undervoltage inhibit feature prevents UFLS relay operation if the sensed voltage decreases below an adjustable setting. An undervoltage inhibit function is intended to prevent operation of a UFLS relay when the transmission supply is lost to distribution station feeding many induction motors. Following loss of the transmission supply, motors may support the voltage while the motors coast down in speed. The motors coasting down (ringing down) will look like an underfrequency event to the relay. The inhibit setting is set to a voltage above which the motor load is expected to sustain. This prevents the underfrequency relay from tripping and locking out distribution feeder breakers supplying the motor load, between the time the transmission supply line trips and the time when the line recloses to restore the load. Voltages sustained by motors that are coasting down (e.g. 0.70 pu) are typically much lower than voltages at which the UFLS relays are required to operate to meet UFLS performance criteria. However, motor loads supplied by cable networks typically have higher ring down voltages because of cable charging. Therefore, care must be taken so that the voltage inhibit setting is not higher than the voltage at which UFLS relays are required to operate to meet UFLS performance criteria.

R5. Each Planning Coordinator shall develop and review settings for inhibit thresholds at least once per five calendar years (such as, but not limited to, voltage, current and time) to be utilized within its region's UFLS program. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M5. Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R5.

R6. Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 calendar days of any changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Each Planning Coordinator shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R6.

R7. Each Distribution Provider and Transmission Owner that receives a notification pursuant to Requirement R6 shall develop and submit an implementation plan with respect to inhibit thresholds for approval by the Planning Coordinator within 90 calendar days of the request from the Planning Coordinator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R7.

R8. Each Distribution Provider and Transmission Owner shall implement the inhibit thresholds provided by the Planning Coordinator in accordance with Requirement R6 and based on the Planning Coordinator approved implementation plan in accordance with R7. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M8. Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets, completed work orders, or other documentation that demonstrates that it meets Requirement R8.

Rationale for Requirement R9: Ideally, the amount of load to be shed in each stage of the UFLS program for every entity should perfectly match that prescribed in this Standard, for all phases of the load cycle, i.e., seasonal (summer vs. winter), weekly (weekday vs. weekend vs. holidays), daily (morning, noon, and night), etc. for all of the identified islands. Practically, however, this is obviously not possible because the load cycles of the various areas and sub-areas within any given island do not perfectly track the load cycle of the overall island. The UFLS program, on the other hand, is designed based on peak conditions for the overall island. The percentages of actual load shedding that would occur for any conditions other than peak, therefore, can only approximate that prescribed in the Standard. To that end, Requirement R11 requires entities to document measured loads in the UFLS program coincident with their own annual peak, whether or not that peak occurs at the same time or in the same season as the peak of the identified island in which their load resides. Using individual entity peaks vs. overall island peaks provides a consistent approach for accounting purposes among the very entities that are responsible for designing and maintaining their UFLS programs.

R9. Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 calendar months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage. The actual net Load shall be coincident with the entity's integrated hourly peak net Load during the previous year, as determined by measuring or calculating Load through the switches that would disconnect load if triggered by the UFLS relays. If measured data is unavailable then calculated data may be used. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M9. Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the net amount of load shed and the percentage of its peak load at each stage of its UFLS program to demonstrate that it meets Requirement R9.

R10. Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, on or below the appropriate generator underfrequency trip protection setting threshold curve in Figure 2, except as otherwise exempted in Requirements R13 and R16. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M10. Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R10.

R11. Each Generator Owner shall transmit the generator underfrequency trip setting and time delay within 45 calendar days of the Planning Coordinator's request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M11. Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R11.

R12. Each Generator Owner with a new generating unit, or an existing generator increasing its net capability by greater than 10% shall: *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

12.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 2.

12.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection setting threshold curve in Figure 2.

M12. Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R12.

R13. For existing non-nuclear units in service prior to July 1, 2015, that have underfrequency protections set to trip above the appropriate curve in Figure 2: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

13.1 Each Generator Owner shall set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

13.2 Each Generator Owner shall transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

13.3 Each Planning Coordinator in Ontario, Québec and the Maritime Provinces shall arrange for compensatory load shedding, in accordance with Attachment A and as provided by a Distribution Provider or Transmission Owner, that is adequate to compensate for the loss of generator(s) due to early tripping that is within the UFLS island identified by the Planning Coordinator in Requirement R2.

13.4 Each Generator Owner in the ISO-NE Planning Coordinator area and in NYISO Planning Coordinator area shall arrange for compensatory load shedding, in accordance with Attachment B and as provided by a Distribution Provider or Transmission Owner, that is adequate to compensate for the loss of generator(s) due to early tripping that is within the UFLS island identified by the Planning Coordinator in Requirement R2.

M13. Each Generator Owner with existing non-nuclear units in service prior to July 1, 2015 which have underfrequency tripping that is not compliant with Requirement R10 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R13.

R14. Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R13.3 for generating units in its respective NPCC area. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M14. Each Planning Coordinator in Ontario, Quebec and Maritime provinces shall provide evidence such as reports, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R14.

R15. Each Generator Owner, Distribution Provider or Transmission Owner within the ISO-NE Planning Coordinator area and in NYISO Planning Coordinator Area shall apply the criteria described in Attachment B to determine the compensatory load shedding that

is required in Requirement R13.4 for generating units in its respective NPCC area. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M15. Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the NYISO shall provide evidence such as reports, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R15.

R16. Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 2 based on their licensing design shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

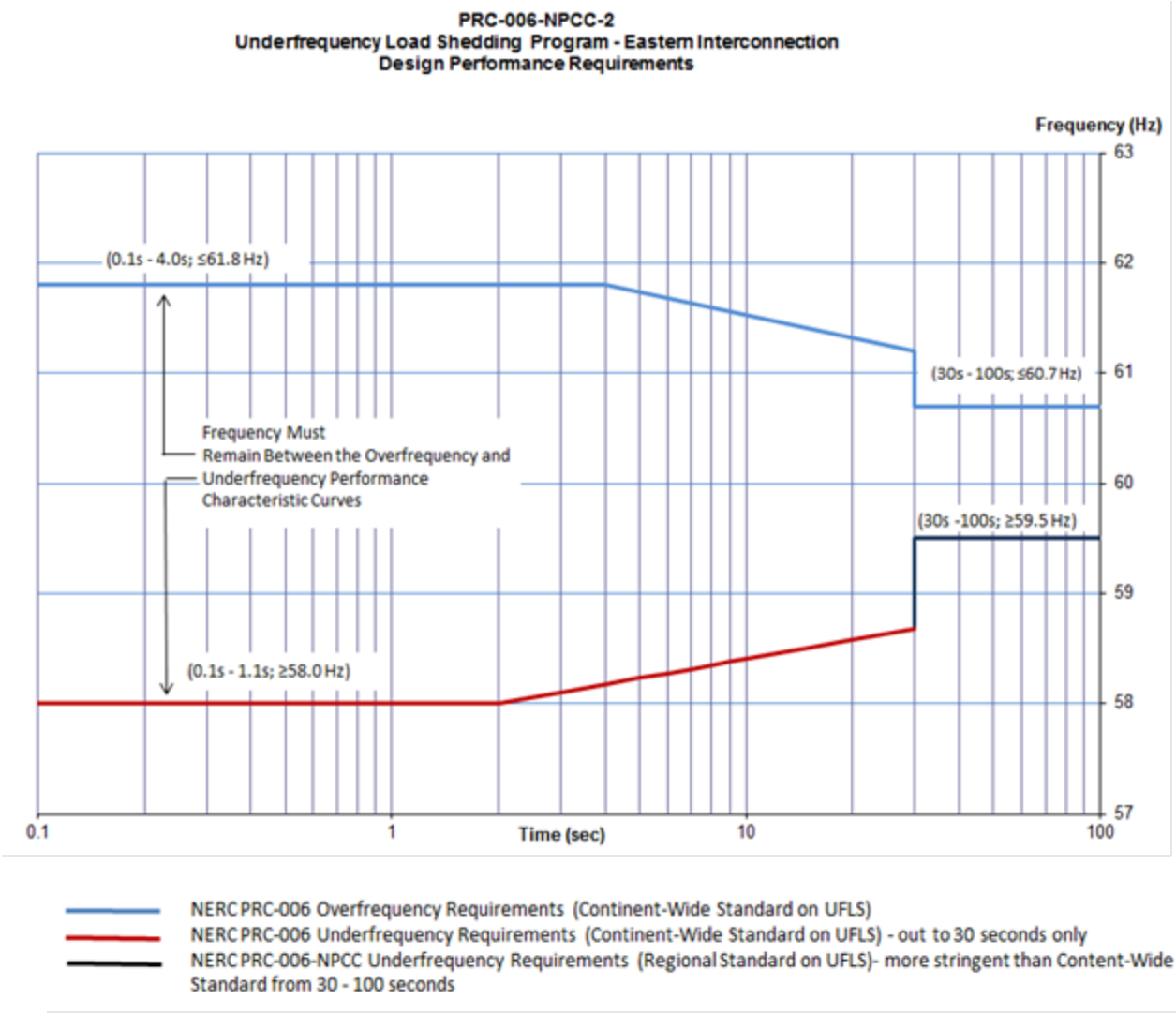
16.1 Set the underfrequency protection to operate at a frequency setting that is as low as possible in accordance with the plant design and licensing limitations but not greater than 57.8 Hz.

16.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.

16.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

M16. Each Generator Owner of nuclear units that have generator trip settings above the generator trip curve in Figure 2 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R16.

Figure 1

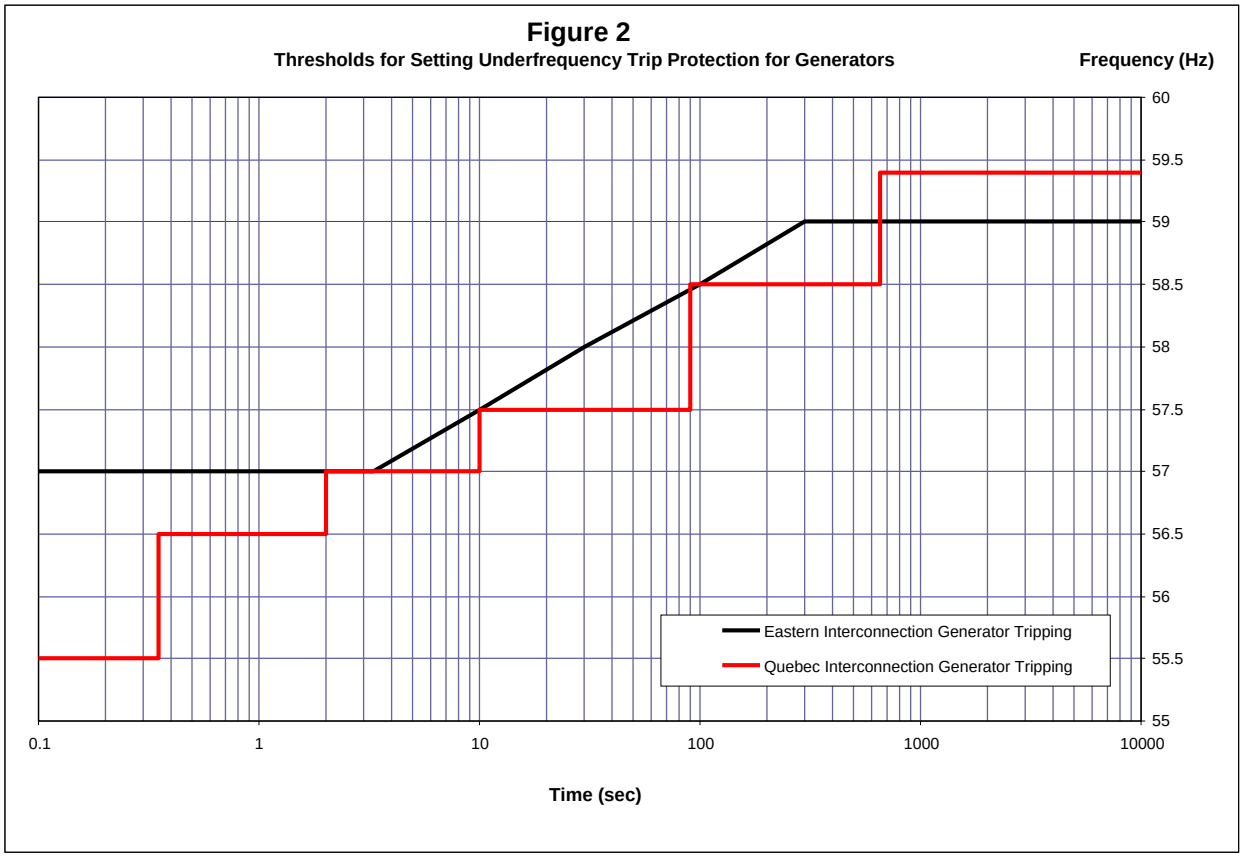


Curve Data:

Overfrequency Requirements		**Source**
t ≤ 4 s	f = 61.8 Hz	NERC PRC-006 (Continent-Wide Standard on UFLS)
4 s < t ≤ 30 s	f = -0.686log(t) + 62.21 Hz	
t > 30 s	f = 60.7 Hz	

Underfrequency Requirements		**Source**
t ≤ 2 s	f = 58.0 Hz	NERC PRC-006 (Continent-Wide Standard on UFLS)
2 s < t ≤ 30 s	f = 0.575log(t) + 57.83 Hz	
t > 30 s	f = 59.5 Hz	NERC PRC-006-NPCC (Regional Standard on UFLS)

Figure 2
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Thresholds for Setting Underfrequency Trip Protection for Generators



C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

Northeast Power Coordinating Council

1.2. Evidence Retention:

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 2, 3, 4, 5, 8, and 9.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 5, 6, and 7.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 15.

The Generator Owner shall keep evidence for three calendar years for Measures 10, 11, 12, 13, and 16.

1.3. Compliance Monitoring and Enforcement Program:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

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 failed to design an UFLS program having performance characteristics that prevent frequency from remaining below 59.5 Hz in accordance with Figure 1.
R2.	The Planning Coordinator provided its UFLS island boundaries, as identified per the NERC continent-wide PRC-006 Standard on UFLS but did so more than 30 calendar days and up to and including 40 days following a request.	The Planning Coordinator provided its UFLS island boundaries, as identified per the NERC continent-wide PRC-006 Standard on UFLS but did so more than 40 calendar days but less than and including 50 days following a request.	The Planning Coordinator provided its UFLS island boundaries, as identified per the NERC continent-wide PRC-006 Standard on UFLS but did so more than 50 calendar days but less than and including 60 days following a request.	The Planning Coordinator failed to provide its UFLS island boundaries, as identified per the NERC continent-wide PRC-006 Standard on UFLS. within 60 calendar days following a request.
R3.	The Distribution Provider or Transmission Owner failed to apply appropriate settings on 20% or less of the relays identified as included in the UFLS program, or amount of load tripped is within 10% deviation from the required amount of Load required to be shed at each stage	The Distribution Provider or Transmission Owner failed to apply appropriate settings on 20%-40% of the relays identified as included in the UFLS program, or amount of load tripped is within 20% deviation from the required amount of Load required to be shed at each stage m	The Distribution Provider or Transmission Owner failed to apply appropriate settings on 40%-60% of the relays identified as included in the UFLS program, or amount of load tripped is within 30% deviation from the required amount of Load required to be shed at each stage.	The Distribution Provider or Transmission Owner failed to apply appropriate settings on > 60% of the relays identified as included in the UFLS program, or amount of load tripped has a > 30% deviation from the required amount of Load required to be shed at each stage
R4.	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program fulfilled its obligations for	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program fulfilled its obligations for	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program fulfilled its obligations but exceeded the permissible	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program failed to meet all of items in Requirement 5 within 60

	Requirement R5, Parts %.1 through Part 5.4 but exceeded the permissible time frame for one or more of the 4 items by a period of up to 10 calendar days but less than or equal to 20 calendar days.	Requirement R5, Parts %.1 through Part 5.4 but exceeded the permissible time frame for one or more of the 4 items within a time greater than 20 calendar days but less than or equal to 30 calendar days.	time frame for one or more of the 4 items within a time greater than 30 calendar days but less than or equal to 60 calendar days.	calendar days of permissible time for each item.
R5.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 100% but more than (and including) 95% of relays within its region's UFLS program.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 95% but more than (and including) 90% of relays within its region's UFLS program.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 90% but more than (and including) 85% of relays within its region's UFLS program.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 85% of relays within its region's UFLS program.
R6.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 calendar days and up to and including 40 calendar days of any changes.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 calendar days but less than and including 50 calendar days of any changes.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 calendar days but less than and including 60 calendar days of any changes.	The Planning Coordinator failed to provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 60 calendar days after any changes
R7.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 calendar days and up to and including 100 calendar days following the request.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 calendar days and up to and including 110 calendar days following the request.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 calendar days and up to and including 120 calendar days following the request.	The Distribution Provider or Transmission Owner failed to develop and submit its implementation plan within 120 days following the request.
R8.	Implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with

	less than 100% but more than (and including) 95% of UFLS relays.	the Planning Coordinator approved implementation plan for less than 95% but more than (and including) 90% of UFLS relays.	the Planning Coordinator approved implementation plan for less than 90% but more than (and including) 85% of UFLS relays.	the Planning Coordinator approved implementation plan for less than 85% of UFLS relays.
R9.	The Distribution Provider or Transmission Owner provided to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 more than 15 calendar months but less than (and including) 16 calendar months since last update.	The Distribution Provider or Transmission Owner provided to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 more than 16 calendar months but less than (and including)17 calendar months since last update.	The Distribution Provider or Transmission Owner provided to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 more than 17 calendar months but less than (and including)18 calendar months since last update.	The Distribution Provider or Transmission Owner failed to provide to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 within 18 calendar months since last update.
R10.	N/A	N/A	N/A	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, on or below the appropriate generator underfrequency trip protection settings threshold curve in Figure 2, except as otherwise exempted.
R11.	The Generator Owner transmitted the generator underfrequency trip setting and time delay more than 45calendar days and less than (and including) 55 calendar days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay more than 55 calendar days and less than (and including) 65 calendar days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay more than 65 calendar days and less than (and including) 75 calendar days of the Planning Coordinator's request.	The Generator Owner failed to transmit the generator underfrequency trip setting and time delay within 75 calendar days of the Planning Coordinator's request.
R12.	N/A	N/A	The Generator Owner with a new generating unit, or an existing	The Generator Owner with a new generating unit, or an existing generator increasing its net

			generator increasing its net capability by greater than 10%: Did not fulfill the obligation of Requirement R12; Part 12.1 OR Did not fulfill the obligation of Requirement R12, Part 12.2.	capability by greater than 10%, did not fulfill the obligations of Requirement R12, Part 12.1 and Part 12.2.
R13.	N/A	The Generator Owner failed to transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinatoras specified in Requirement R13, Part 13.2.	The Generator Owner failed to set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations a specified in Requirement 13, Part 13.1	The Planning Coordinator in Ontario, Québec and the Maritime Provinces or the Generator Owner within the ISO-NE and in NYISO Planning Coordinator areas failed to arrange for compensatory load shedding as specified in Requirement R13, Part 13.3.
R14.	N/A	N/A	N/A	The Planning Coordinator did not apply the criteria described in Attachment A to determine the compensatory load shedding that is required.
R15.	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or Transmission Owner did not apply the criteria described in Attachment B to determine the compensatory load shedding that is required.
R16.	N/A	The Generator Owner failed to transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning	The Generator Owner: Failed to set the underfrequency protection as specified in Requirement R16; Part 16.1 OR	The Generator Owner did not fulfill the obligations of Requirement R16, Part 16.1 and Part 16.2.

		Coordinator as specified in Requirement R16, Part 16.3.	Failed to set the frequency trip setting upper tolerance as specified in Requirement R16, Part 16.2.	

D. Regional Variances

None.

E. Associated Documents

Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	2-9-2012	Adopted by Board of Trustees	
2	6-23-2015	RSAR Submitted	

Standard Attachments

PRC-006-NPCC-2 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 2. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all UFLS islands in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements as part of its UFLS Assessment based on the NERC PRC Standard on UFLS:

1. The Planning Coordinator shall identify, compile and maintain a list of all existing non-nuclear generating units in their Planning Coordinator area that were in service prior to the effective date of the regional Standard (July 1, 2015 PRC-006-NPCC-1). The list must indicate generating units, if any, that have their underfrequency protections set to trip above the appropriate curve in Figure 2. Generating Units not appearing on the list as of the effective date of Version 1 of the regional standard, as shown above, must have their Underfrequency protections set to trip on or below the appropriate curve in Figure 2. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator within which the generator may operate to provide compensatory load shedding.

    2.2 In Ontario and in the Maritime provinces, the compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in

addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 2 during an underfrequency event. If the highest frequency at which the subject generator will trip above the appropriate curve in Figure 2 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 2.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-2 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 2 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify, compile, and maintain a list of all of its existing non-nuclear generating units that were in service prior to the effective date of the regional Standard (July 1, 2015 PRC-006-NPCC-1). The list must indicate the Generator Owner's generating units, if any, which have their underfrequency protections set to trip above the appropriate curve in Figure 2. Generating Units not appearing on the list as of the effective date of Version 1 of the regional standard, as shown above, must have their Underfrequency protections set to trip on or below the appropriate curve in Figure 2. The list shall include the following information associated with each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 2, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the same and smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 2, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the same and smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-2 Attachment C

UFLS Table 1: Eastern Interconnection Distribution Providers and Transmission Owners with 100 MW[2] or more of peak net Load shall implement a UFLS program with the following attributes:					
UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.10	0.30	6.5 – 7.5	6.5 – 7.5
2	59.3	0.10	0.30	6.5 – 7.5	13.5 – 14.5
3	59.1	0.10	0.30	6.5 – 7.5	20.5 – 21.5
4	58.9	0.10	0.30	6.5 – 7.5	27.5 – 28.5
5	59.5	0.10	10.0	2 - 3	29.5 – 31.5

UFLS Table 2: Eastern Interconnection Distribution Providers and Transmission Owners with 50 MW[2] or more and less than 100 MW[2] of peak net Load shall implement a UFLS program with the following attributes:					
UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.10	0.30	14 – 25	14 – 25
2	59.1	0.10	0.30	14 – 25	28 – 50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.
2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

UFLS Table 3: Eastern Interconnection Distribution Providers and Transmission Owners with 25 MW[2] or more and less than 50 MW[2] of peak net Load shall implement a UFLS program with the following attributes:					
UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.10	0.30	28 – 50	28 – 50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.
2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

Rationale Box:

Standard PRC-006-3, R4 requires the Planning Coordinator to conduct a UFLS assessment at least once every five years. However, aside from a UFLS islanding event, it does not prescribe other factors or events which could warrant a new UFLS assessment in less than the five years time-frame.
PRC-006-NPCC-01 contained requirements if changes to load distribution impacted UFLS program performance (R21) but did not consider many other factors. The drafting team recommends retiring these requirements (R21, R22, R23) and replacing them with the following guidance.
Significant variations in the following factors could require a Planning Coordinator to conduct a new assessment:

- Changes to the BES that could modify the creation of islands or the severity of events such as new transmission topologies, revised protection schemes or new or revised RAS.
- Unforeseen islanding event
- Real and reactive load distribution (including changes to location of compensatory load shedding)
- Transmission Owner or Distribution Provider's inability to implement the UFLS program within the stated tolerances
- Load characteristics in particular frequency responsive load
- Automatic load restoration
- Generation geographical distribution
- Generator trip settings
- Generation mix in particular non-BES generation that may not be subject to frequency ride-through criteria
- Generator dynamic modeling
- Dynamic VAR device modeling
- HVDC dynamic modeling

A. Introduction

~~2.1~~1. **Title:** **Automatic Underfrequency Load Shedding**

~~2.2~~2. **Number:** PRC-006-NPCC-2~~1~~

~~2.3~~3. **Purpose:** The NPCC Automatic Underfrequency Load Shedding (UFLS) regional Reliability Standard establishes more stringent and specific NPCC UFLS program requirements than the NERC continent-wide PRC-006 standard. The program is designed such that declining frequency is arrested and recovered in accordance with established NPCC performance requirements stipulated in this document~~To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics~~.

~~2.4~~4. **Applicability:**

~~a.~~4.1. Generator Owner

~~b.~~4.2. Planning Coordinator

~~c.~~4.3. Distribution Providers that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators~~Distribution Provider~~

~~d.~~4.4. Transmission Owners that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators~~Transmission Owner~~

~~2.5~~5. **Effective Date:**

See Implementation Plan ~~For the Eastern Interconnection & Québec Interconnection portions of NPCC excluding the Independent Electricity System Operator (IESO) Planning Coordinator area of NPCC in Ontario, Canada:~~

~~The effective date for Requirements R1, R2, R3, R4, R5, R6, and R7 is the first day of the first calendar quarter following applicable regulatory approval but no earlier than January 1, 2016 The effective date for Requirements R8 through R23 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.~~

~~For the Independent Electricity System Operator (IESO) Planning Coordinator's area of NPCC in Ontario, Canada:~~

~~All requirements are effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017~~.

B. Requirements

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~~Adopted by Board of Trustees: February 9, 2012~~

Rationale for Requirement R1: Figure 1 of this document shows the NPCC underfrequency criteria for the Eastern Interconnection portion of NPCC. Figure 1 also shows the NERC criteria as defined in the NERC PRC Standard on UFLS.

R1. Each Planning Coordinator in the Eastern Interconnection portion of NPCC shall design an UFLS program, pertaining to islands wholly within the NPCC Region, having performance characteristics that prevents the frequency from remaining below 59.5 Hz for more than 30 seconds in accordance with Figure 1 *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M1. Each Planning Coordinator shall have evidence such as reports, system studies and/or real-time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

R2. Each Planning Coordinator shall provide UFLS island boundaries, as identified per the NERC continent wide PRC-006 Standard on UFLS, to Distribution Providers, Generator Owners, and Transmission Owners within 30 calendar days of receipt of a request. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

R3. Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program, reflecting normal operating conditions, excluding outages. The automatic UFLS program shall be implemented on an island basis for each identified island per the NERC continent wide PRC-006 Standard on UFLS as follows: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

- The UFLS program shall be implemented by each Distribution Provider and Transmission Owner according to the frequency thresholds, nominal operating times, and load shedding amounts specified in Attachment C, Tables 1-3; or
- The UFLS program shall be implemented collectively by multiple Distribution Providers or Transmission Owners, as long as they reside in the same UFLS island identified by the Planning Coordinator per Requirement R2. These multiple Distribution Providers or Transmission Owners, via mutual agreement, shall act as a single entity to provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load according to the frequency thresholds, total nominal operating time, and load shedding amounts specified in Attachment C, Tables 1-3.

M3. Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped in their respective areas, and the corresponding frequency thresholds, on those circuits included in its UFLS program identified in Requirement R3. (Attachment C, Tables 1-3).

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R4. Each Distribution Provider or Transmission Owner in the Eastern Interconnection portion of NPCC that does not meet the UFLS program parameters specified in Attachment C, Table 1-3, and each Distribution Provider or Transmission Owner in the Quebec Interconnection that does not meet the UFLS program parameters specified by its Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

- Within 30 calendar days of determining that it does not meet the specified parameters, notify its Planning Coordinator that it does not meet the UFLS program parameters; and
- Within the following 180 calendar days from notification of the Planning Coordinator,

(1) develop a Corrective Action Plan and a schedule for implementation that is mutually agreed upon with its Planning Coordinator or
(2) provide its Planning Coordinator with a technical study that demonstrates that the deviations from the program parameters will not result in failure of UFLS performance criteria being met for any island. The technical study must be acceptable to the Planning Coordinator prior to implementing deviations from program parameters and shall demonstrate coordination with UFLS programs of all entities residing within the same island(s) identified by the Planning Coordinator in Requirement R2. The technical study shall also demonstrate coordination with other UFLS programs of adjoining Planning Coordinators, or
(3) provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3

M4. Each Distribution Provider or Transmission Owner shall have evidence such as reports analysis, system studies and dated documentation that demonstrates that it meets Requirement R4.

~~**R1** Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS). [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]~~

Rationale for Requirement R5: An inhibit function provides supervisory control over a UFLS relay. For example, an undervoltage inhibit feature prevents UFLS relay operation if the sensed voltage decreases below an adjustable setting. An undervoltage inhibit function is intended to prevent operation of a UFLS relay when the transmission supply is lost to distribution station feeding many induction motors. Following loss of the transmission supply, motors may support the voltage while the motors coast down in speed. The motors coasting down (ringing down) will look like an underfrequency event to the relay. The inhibit setting is set to a voltage above which the motor load is expected to sustain. This prevents the underfrequency relay from tripping and locking out distribution feeder breakers supplying the motor load, between the time the transmission supply line trips and

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the time when the line recloses to restore the load. Voltages sustained by motors that are coasting down (e.g. 0.70 pu) are typically much lower than voltages at which the UFLS relays are required to operate to meet UFLS performance criteria. However, motor loads supplied by cable networks typically have higher ring down voltages because of cable charging. Therefore, care must be taken so that the voltage inhibit setting is not higher than the voltage at which UFLS relays are required to operate to meet UFLS performance criteria.

R5. Each Planning Coordinator shall develop and review settings for inhibit thresholds at least once per five calendar years (such as, but not limited to, voltage, current and time) to be utilized within its region's UFLS program. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M5. Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R5.

R6. Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 calendar days of any changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Each Planning Coordinator shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R6.

R7. Each Distribution Provider and Transmission Owner that receives a notification pursuant to Requirement R6 shall develop and submit an implementation plan with respect to inhibit thresholds for approval by the Planning Coordinator within 90 calendar days of the request from the Planning Coordinator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R7.

R8. Each Distribution Provider and Transmission Owner shall implement the inhibit thresholds provided by the Planning Coordinator in accordance with Requirement R6 and based on the Planning Coordinator approved implementation plan in accordance with R7. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M8. Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets, completed work orders, or other documentation that demonstrates that it meets Requirement R8.

Rationale for Requirement R9: Ideally, the amount of load to be shed in each stage of the UFLS program for every entity should perfectly match that prescribed in this Standard, for all phases of the load cycle, i.e., seasonal (summer vs. winter), weekly (weekday vs. weekend vs. holidays), daily (morning, noon, and night), etc. for all of the identified islands. Practically, however, this is obviously not possible because the load cycles of the

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various areas and sub-areas within any given island do not perfectly track the load cycle of the overall island. The UFLS program, on the other hand, is designed based on peak conditions for the overall island. The percentages of actual load shedding that would occur for any conditions other than peak, therefore, can only approximate that prescribed in the Standard. To that end, Requirement R11 requires entities to document measured loads in the UFLS program coincident with their own annual peak, whether or not that peak occurs at the same time or in the same season as the peak of the identified island in which their load resides. Using individual entity peaks vs. overall island peaks provides a consistent approach for accounting purposes among the very entities that are responsible for designing and maintaining their UFLS programs.

R9. Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 calendar months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage. The actual net Load shall be coincident with the entity's integrated hourly peak net Load during the previous year, as determined by measuring or calculating Load through the switches that would disconnect load if triggered by the UFLS relays. If measured data is unavailable then calculated data may be used. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M9. Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the net amount of load shed and the percentage of its peak load at each stage of its UFLS program to demonstrate that it meets Requirement R9.

R10. Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, on or below the appropriate generator underfrequency trip protection setting threshold curve in Figure 2, except as otherwise exempted in Requirements R13 and R16. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M10. Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R10.

R11. Each Generator Owner shall transmit the generator underfrequency trip setting and time delay within 45 calendar days of the Planning Coordinator's request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M11. Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R11.

R12. Each Generator Owner with a new generating unit, or an existing generator increasing its net capability by greater than 10% shall: *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*,

12.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 2.

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12.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection setting threshold curve in Figure 2.

~~**R2 Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]**~~

~~**R3 Each Planning Coordinator shall provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1. [Violation Risk Factor: Low] [Time Horizon: Long Term Planning]**~~

~~**R4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3, or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3.**~~
~~**[Violation Risk Factor: High] [Time Horizon: Long Term Planning]**~~

~~**R5 Each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on its total peak net Load shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]**~~

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5.1 Inform its Planning Coordinator of the need to exceed the stated tolerances or the number of stages as shown in UFLS Attachment C, Table 1 if applicable and

5.2 Provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the bulk power system.

5.3 Inform its Planning Coordinator of the need to exceed the stated tolerances of UFLS Attachment C, Table 2 or Table 3, and in the case of Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and

5.4 Provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3.

R6. Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R7. Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with the following minimum time delay:

7.1 Eastern Interconnection – 100 ms

7.2 Québec Interconnection – 200 ms

[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R8. Each Planning Coordinator shall develop and review once per calendar year settings for inhibit thresholds (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

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~~R9 Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]~~

~~R10 Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R9. [Violation Risk Factor: High] [Time Horizon: Operations Planning]~~

~~R11 Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R9. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]~~

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~~R12 Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]~~

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~~R13 Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R16 and R19. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

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~~R14 Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request. [Violation Risk Factor: High] [Time Horizon: Operations Planning]~~

R15 Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net capability by greater than 10% shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

15.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1.

15.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1.

R16 Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

16.1 Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

16.2 Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

16.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.

R17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R16.3 for

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~~generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

~~R19. Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 1, based on their licensing design basis, shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

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~~19.1 Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8Hz.~~

~~19.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.~~

~~19.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.~~

~~R20 The Planning Coordinator shall update its UFLS program database as specified by the NERC PRC Standard on UFLS. This database shall include the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]~~

~~20.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings.~~

~~20.2 The buses at which the Load is modeled in the NPCC library power flow case.~~

~~20.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system.~~

~~20.4 The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.~~

~~20.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.~~

~~**R21. Each Planning Coordinator shall notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]**~~

~~**R22. Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]**~~

~~**R23 Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]**~~

M12. Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R12.

R13. For existing non-nuclear units in service prior to July 1, 2015, that have underfrequency protections set to trip above the appropriate curve in Figure 2: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

13.1 Each Generator Owner shall set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

13.2 Each Generator Owner shall transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

13.3 Each Planning Coordinator in Ontario, Québec and the Maritime Provinces shall arrange for compensatory load shedding, in accordance with Attachment A and as provided by a Distribution Provider or Transmission Owner, that is adequate to compensate for the loss of generator(s) due to early tripping that is within the UFLS island identified by the Planning Coordinator in Requirement R2.

13.4 Each Generator Owner in the ISO-NE Planning Coordinator area and in NYISO Planning Coordinator area shall arrange for compensatory load shedding, in accordance with Attachment B and as provided by a Distribution Provider or Transmission Owner, that is adequate to compensate for the loss of generator(s) due to early tripping that is within the UFLS island identified by the Planning Coordinator in Requirement R2.

M13. Each Generator Owner with existing non-nuclear units in service prior to July 1, 2015 which have underfrequency tripping that is not compliant with Requirement R10 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R13.

R14. Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R13.3 for generating units in its respective NPCC area. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M14. Each Planning Coordinator in Ontario, Quebec and Maritime provinces shall provide evidence such as reports, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R14.

R15. Each Generator Owner, Distribution Provider or Transmission Owner within the ISO-NE Planning Coordinator area and in NYISO Planning Coordinator Area shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R13.4 for generating units in its respective NPCC area. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M15. Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the NYISO shall provide evidence such as reports, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R15.

R16. Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 2 based on their licensing design shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

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16.1 Set the underfrequency protection to operate at a frequency setting that is as low as possible in accordance with the plant design and licensing limitations but not greater than 57.8 Hz.

16.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.

16.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

M16. Each Generator Owner of nuclear units that have generator trip settings above the generator trip curve in Figure 2 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R16.

Figure 1

Thresholds for Setting Underfrequency Trip Protection for Generators

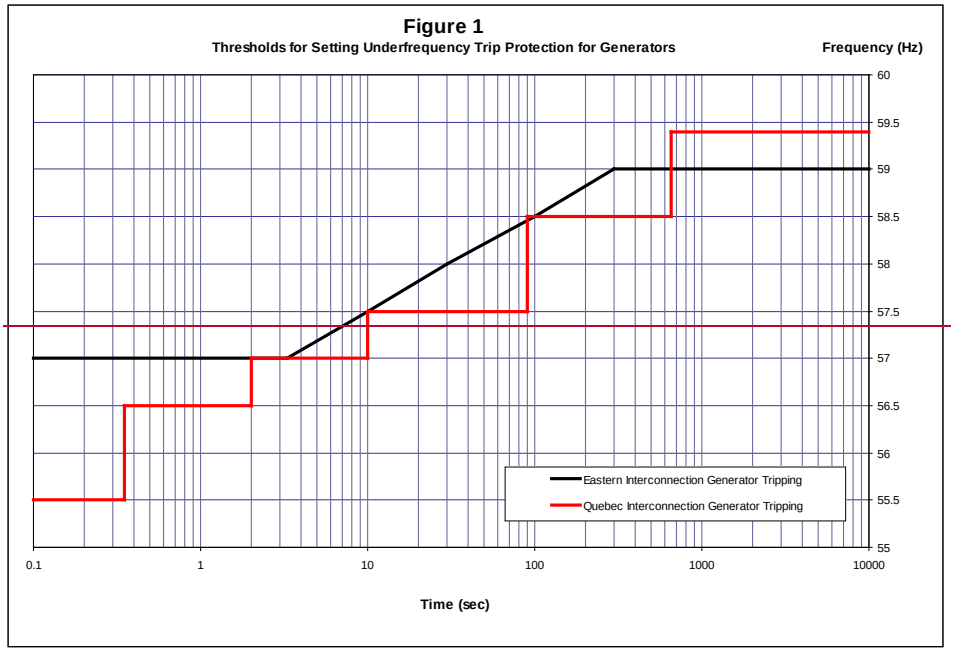
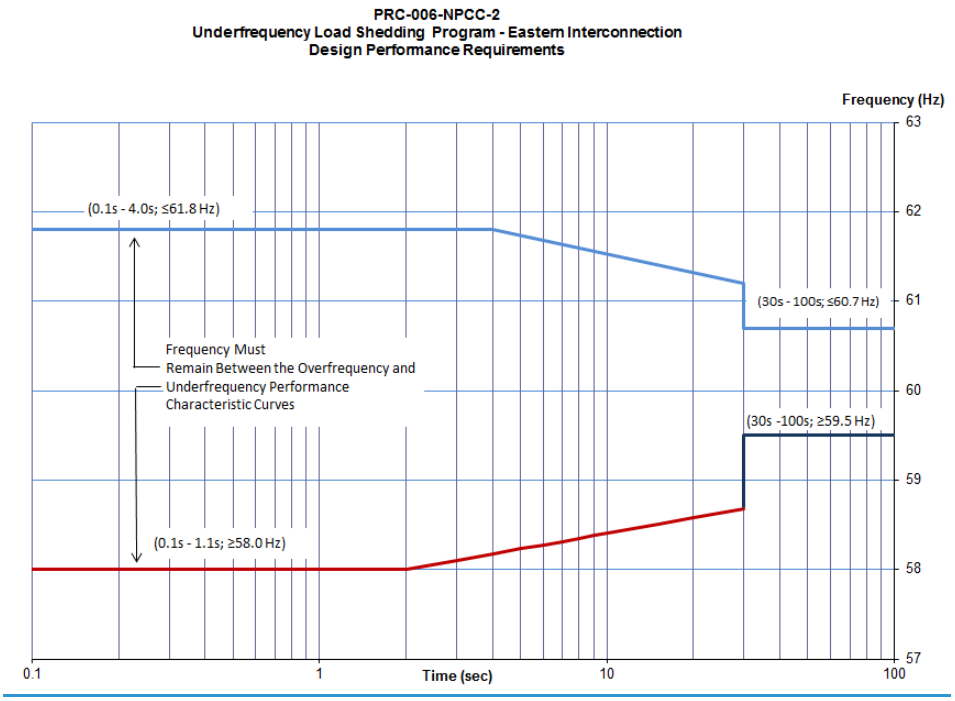


Figure 1

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NERC PRC-006 Overfrequency Requirements (Continent-Wide Standard on UFLS)
NERC PRC-006 Underfrequency Requirements (Continent-Wide Standard on UFLS) - out to 30 seconds only
NERC PRC-006-NPCC Underfrequency Requirements (Regional Standard on UFLS)- more stringent than Content-Wide Standard from 30 - 100 seconds

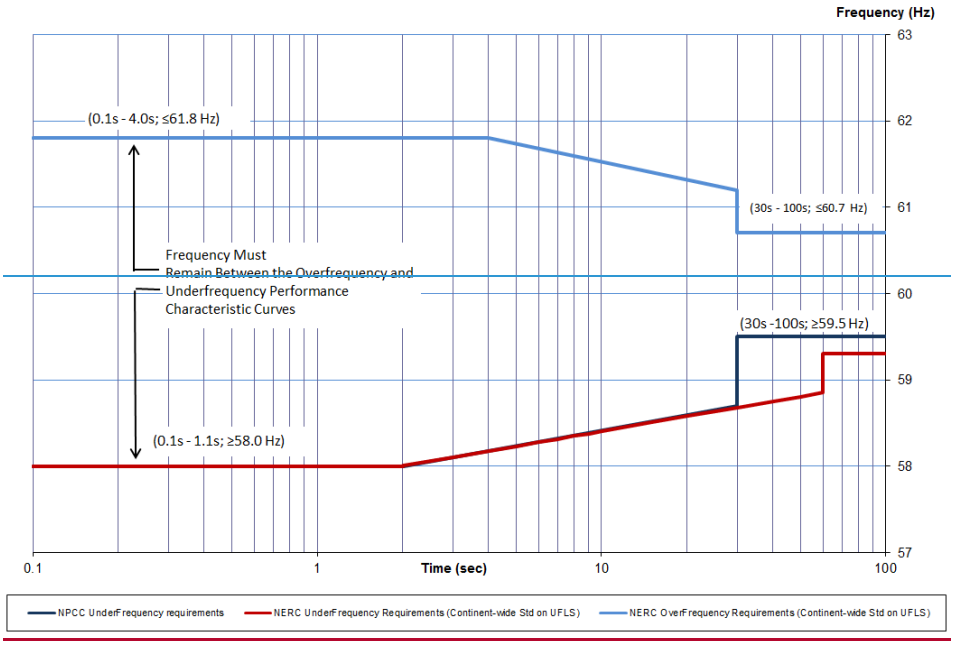
Curve Data:

Overfrequency Requirements		Source
t ≤ 4 s	f = 61.8 Hz	~~NERC PRC-006 (Continent-Wide Standard on UFLS)~~
4 s < t ≤ 30 s	f = -0.686log(t) + 62.21 Hz	
t > 30 s	f = 60.7 Hz	

Underfrequency Requirements		Source
t ≤ 2 s	f = 58.0 Hz	NERC PRC-006 (Continent-Wide Standard on UFLS)
2 s < t ≤ 30 s	f = 0.575log(t) + 57.83 Hz	
t > 30 s	f = 59.5 Hz	NERC PRC-006-NPCC (Regional Standard on UFLS)

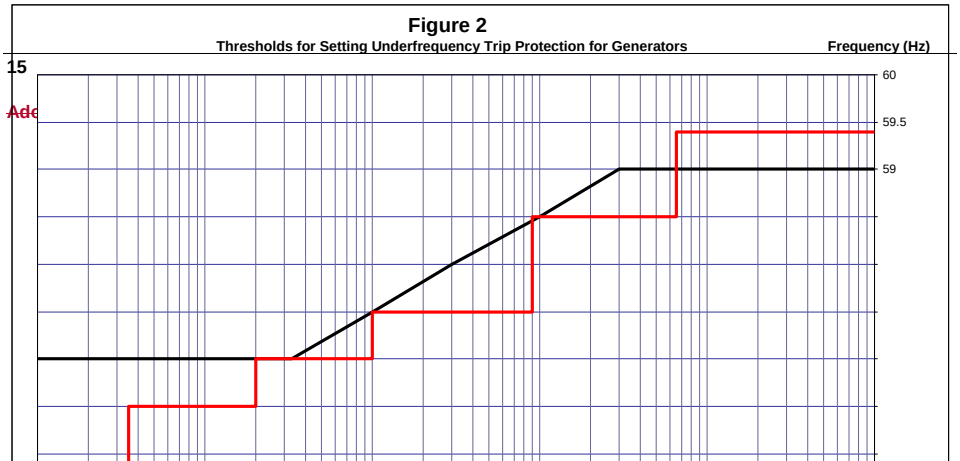
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PRC-006-NPCC-2 Figure 1
Underfrequency Load Shedding Program - Eastern Interconnection
Design Performance Requirements



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Figure 2
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Thresholds for Setting Underfrequency Trip Protection for Generators



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~~C. Measures~~

M1 Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

M3 Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

M4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4. (Attachment C Tables 1-3).

M5 Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

M6 Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R6. (Attachment C Table 4).

M7 Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R7.

M8 Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R8.

M9 Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

M10 Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R10.

M11 Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R11.

M12 Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R12.

M13 Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R13.

M14 Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R14.

M15 Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R15.

M16 Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R16.

M17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R17.

M18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R18.

M19 Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R19.

M20 Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R20.

M21 Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R21.

M22 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R22.

M23 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement 23.

~~D.~~C. Compliance

~~1.1~~1. Compliance Monitoring Process

~~a.~~1.1. Compliance Enforcement Authority

Northeast Power Coordinating Council~~PCC Compliance Committee~~

~~a. Compliance Monitoring Period and Reset Time Frame~~

~~Not Applicable~~

~~b.~~1.2. ~~Data~~Evidence ~~-~~Retention

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 2~~4~~, 3~~5~~, 4~~6~~, 5~~7~~, 8~~10~~, and ~~11~~9~~, and 12~~.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 5, ~~3, 8~~6, and 7~~9~~, ~~20, and 21~~.

~~The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 17.~~

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The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 1~~8~~5~~, 22, and 23~~.

The Generator Owner shall keep evidence for three calendar years for Measures 10~~3~~, 11~~4~~, 12~~5~~, 13~~6~~, and 16~~9~~.

~~c.~~1.3.Compliance Monitoring and Assessment Processes

Com~~Self-Certifications.~~

~~Spot Checking.~~

~~Compliance Audits.~~

~~Self-Reporting.~~

~~Compliance Violation Investigations.~~

~~Complaints.~~pliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

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~~**d. Additional Compliance Information**~~

~~None.~~

~~1.2~~1. Violation Severity Levels

Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Planning Coordinator failed to design an UFLS program having performance characteristics that prevent frequency from remaining below 59.5 Hz in accordance with Figure 1.
R2	The Planning Coordinator provided its UFLS island boundaries, as identified per the NERC continent-wide PRC-006 Standard on UFLS but did so more than 30 calendar days and up to and including 40 days following a request.	The Planning Coordinator provided its UFLS island boundaries, as identified per the NERC continent-wide PRC-006 Standard on UFLS but did so more than 40 calendar days but less than and including 50 days following a request.	The Planning Coordinator provided its UFLS island boundaries, as identified per the NERC continent-wide PRC-006 Standard on UFLS but did so more than 50 calendar days but less than and including 60 days following a request.	The Planning Coordinator failed to provide its UFLS island boundaries, as identified per the NERC continent-wide PRC-006 Standard on UFLS. within 60 calendar days following a request.
R3	The Distribution Provider or Transmission Owner failed to apply appropriate settings on 20% or less of the relays identified as included in the UFLS program, or amount of load tripped is within 10% deviation from the required amount of	The Distribution Provider or Transmission Owner failed to apply appropriate settings on 20%-40% of the relays identified as included in the UFLS program, or amount of load tripped is within 20% deviation from the required amount of Load	The Distribution Provider or Transmission Owner failed to apply appropriate settings on 40%-60% of the relays identified as included in the UFLS program, or amount of load tripped is within 30% deviation from the required amount of	The Distribution Provider or Transmission Owner failed to apply appropriate settings on > 60% of the relays identified as included in the UFLS program, or amount of load tripped has a > 30% deviation from the required amount of Load required

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~~Adopted by Board of Trustees: February 9, 2012~~

	Load required to be shed at each stage	required to be shed at each stage m	Load required to be shed at each stage.	to be shed at each stage
R4	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program fulfilled its obligations for Requirement R5, Parts %.1 through Part 5.4 but exceeded the permissible time frame for one or more of the 4 items by a period of up to 10 calendar days but less than or equal to 20 calendar days.	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program fulfilled its obligations for Requirement R5, Parts %.1 through Part 5.4 but exceeded the permissible time frame for one or more of the 4 items within a time greater than 20 calendar days but less than or equal to 30 calendar days.	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program fulfilled its obligations but exceeded the permissible time frame for one or more of the 4 items within a time greater than 30 calendar days but less than or equal to 60 calendar days.	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program failed to meet all of items in Requirement 5 within 60 calendar days of permissible time for each item.
R5	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 100% but more than (and including) 95% of relays within its region's UFLS program.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 95% but more than (and including) 90% of relays within its region's UFLS program.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 90% but more than (and including) 85% of relays within its region's UFLS program.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 85% of relays within its region's UFLS program.
R6	The Planning Coordinator provided to a Transmission	The Planning Coordinator provided to a Transmission Owner	The Planning Coordinator provided to a Transmission	The Planning Coordinator failed to provide to a

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	Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 calendar days and up to and including 40 calendar days of any changes.	or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 calendar days but less than and including 50 calendar days of any changes.	Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 calendar days but less than and including 60 calendar days of any changes.	Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 60 calendar days after any changes
R7	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 calendar days and up to and including 100 calendar days following the request.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 calendar days and up to and including 110 calendar days following the request.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 calendar days and up to and including 120 calendar days following the request.	The Distribution Provider or Transmission Owner failed to develop and submit its implementation plan within 120 days following the request.
R8	Implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 100% but more than (and including) 95% of UFLS relays.	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 95% but more than (and including) 90% of UFLS relays.	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 90% but more than (and including) 85% of UFLS relays.	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 85% of UFLS relays.

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R9	The Distribution Provider or Transmission Owner provided to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 more than 15 calendar months but less than (and including) 16 calendar months since last update.	The Distribution Provider or Transmission Owner provided to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 more than 16 calendar months but less than (and including)17 calendar months since last update.	The Distribution Provider or Transmission Owner provided to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 more than 17 calendar months but less than (and including)18 calendar months since last update.	The Distribution Provider or Transmission Owner failed to provide to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 within 18 calendar months since last update.
R10	N/A	N/A	N/A	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, on or below the appropriate generator underfrequency trip protection settings threshold curve in Figure 2, except as otherwise exempted.
R11	The Generator Owner transmitted the generator underfrequency trip setting and time delay more than 45calendar	The Generator Owner transmitted the generator underfrequency trip setting and time delay more than 55 calendar	The Generator Owner transmitted the generator underfrequency trip setting and time delay more than 65 calendar	The Generator Owner failed to transmit the generator underfrequency trip setting and time delay within 75 calendar days

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	days and less than (and including) 55 calendar days of the Planning Coordinator's request.	days and less than (and including) 65 calendar days of the Planning Coordinator's request.	days and less than (and including) 75 calendar days of the Planning Coordinator's request.	of the Planning Coordinator's request.
R12	N/A	N/A	The Generator Owner with a new generating unit, or an existing generator increasing its net capability by greater than 10%: Did not fulfill the obligation of Requirement R12; Part 12.1 OR Did not fulfill the obligation of Requirement R12, Part 12.2.	The Generator Owner with a new generating unit, or an existing generator increasing its net capability by greater than 10%, did not fulfill the obligations of Requirement R12, Part 12.1 and Part 12.2.
R13	N/A	The Generator Owner failed to transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinatoras specified in Requirement R13, Part 13.2.	The Generator Owner failed to set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations a specified in Requirement 13, Part 13.1	The Planning Coordinator in Ontario, Québec and the Maritime Provinces or the Generator Owner within the ISO-NE and in NYISO Planning Coordinator areas failed to arrange for compensatory load shedding as specified in Requirement R13, Part 13.3.
R14	N/A	N/A	N/A	The Planning Coordinator did not

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				apply the criteria described in Attachment A to determine the compensatory load shedding that is required.
R15	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or Transmission Owner did not apply the criteria described in Attachment B to determine the compensatory load shedding that is required.
R16	N/A	The Generator Owner failed to transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator as specified in Requirement R16, Part 16.3.	The Generator Owner: Failed to set the underfrequency protection as specified in Requirement R16; Part 16.1 OR Failed to set the frequency trip setting upper tolerance as specified in Requirement R16, Part 16.2.	The Generator Owner did not fulfill the obligations of Requirement R16, Part 16.1 and Part 16.2.

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PRC-006-NPCC-1 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 2. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all UFLS islands in which the unit may operate~~The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 1. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate~~.

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The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements as part of its UFLS Assessment based on the NERC PRC Standard on UFLS:

1. The Planning Coordinator shall identify, compile and maintain a list of all existing non-nuclear generating units in their Planning Coordinator area that were in service prior to the effective date of the regional Standard (July 1, 2015 PRC-006-NPCC-1). The list must indicate generating units, if any, that have their underfrequency protections set to trip above the appropriate curve in Figure 2. Generating Units not appearing on the list as of the effective date of Version 1 of the regional standard, as shown above, must have their Underfrequency protections set to trip on or below the appropriate curve in Figure 2. The list shall include the following information for each unit~~The Planning Coordinator shall identify, compile and maintain an updated list of all existing non-nuclear generating units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1. The list shall include the following information for each unit~~:

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   1.1 Generator name and generating capacity
   1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
   1.3 Physical and electrical location of the unit
   1.4 All islands within which the unit may operate, as identified in Requirement R1

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2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

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2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator within which the generator may operate to provide compensatory load shedding~~Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding~~.

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2.2 In Ontario and in the Maritime provinces, ~~T~~the compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4~~.~~.

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2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 2 during an underfrequency event. If the highest frequency at which the subject generator will trip above the appropriate curve in Figure 2 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 2~~The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 during an underfrequency event. If the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1~~.

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2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system~~The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system~~.

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In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability

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of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility~~In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility~~.

PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 2 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements~~The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 1 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements~~:

1. The Generator Owner shall identify, compile, and maintain a list of all of its existing non-nuclear generating units that were in service prior to the effective date of the regional Standard (July 1, 2015 PRC-006-NPCC-1). The list must indicate the Generator Owner's generating units, if any, which have their underfrequency protections set to trip above the appropriate curve in Figure 2. Generating Units not appearing on the list as of the effective date of Version 1 of the regional standard, as shown above, must have their Underfrequency protections set to trip on or below the appropriate curve in Figure 2. The list shall include the following information associated with each unit~~The Generator Owner shall identify and compile a list of all existing non-nuclear generating units in service prior to the effective date of this standard that has underfrequency protection set to trip above the appropriate curve in Figure 1. The list shall include the following information associated with each unit~~:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 2, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the same and smallest island identified by the Planning Coordinator in Requirement R1 of this standard~~In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 1, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard~~.

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2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 2, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the same and smallest island identified by the Planning Coordinator in Requirement R1 of this standard~~In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard~~.

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2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4~~The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4~~.

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2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip ~~The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip~~.

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2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system~~The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system~~.

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In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility~~In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two~~

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~~calendar years, plus expected station loads to be transferred to the system upon loss of the facility~~.

PRC-006-NPCC-1 Attachment C

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UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:

Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
59.5	0.30	6.5 – 7.5	6.5 – 7.5
59.3	0.30	6.5 – 7.5	13.5 – 14.5
59.1	0.30	6.5 – 7.5	20.5 – 21.5
58.9	0.30	6.5 – 7.5	27.5 – 28.5
59.5	10.0	2 – 3	– 31.5

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UFLS Table 2: Eastern Interconnection

Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time(s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	14-25	14-25
2	59.1	0.30	14-25	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

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UFLS Table 3: Eastern Interconnection

Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	28 50	28 50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

~~UFLS Table 4: Quebec Interconnection~~

	~~Rate~~	~~Frequency (Hz)~~	~~MW at peak (*Load must be fixed at all times when above 60% of peak load..)~~	~~Mvar at peak~~	~~Total Nominal Operating Time (s)~~ [2]
~~Threshold Stage 1~~	~~——~~	~~58.5~~	~~1000*~~	~~1000~~	~~0.30~~
~~Threshold Stage 2~~	~~——~~	~~58.0~~	~~800*~~	~~800~~	~~0.30~~
~~Threshold Stage 3~~	~~——~~	~~57.5~~	~~800~~	~~800~~	~~0.30~~
~~Threshold Stage 4~~	~~——~~	~~57.0~~	~~800~~	~~800~~	~~0.30~~
~~Threshold Stage 5 (anti-stall)~~	~~——~~	~~59.0~~	~~500~~	~~500~~	~~20.0~~
~~Slope Stage 1~~	~~-0.3 Hz/s~~	~~58.5~~	~~400~~	~~400~~	~~0.30~~
~~Slope Stage 2~~	~~-0.4 Hz/s~~	~~59.8~~	~~800*~~	~~800~~	~~0.30~~
~~Slope Stage 3~~	~~-0.6 Hz/s~~	~~59.8~~	~~800*~~	~~800~~	~~0.30~~
~~Slope Stage 4~~	~~-0.9 Hz/s~~	~~59.8~~	~~800~~	~~800~~	~~0.30~~

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW[2] or more of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold	Minimum Relay Time	Total Nominal	Load Shed at Stage as % of	Cumulative Load Shed as

~~2. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. The underfrequency relay operating time shall be measured from the time when the frequency passes through the frequency threshold set point.~~

	(Hz)	Delay (s)	Operating Time (s)[2]	TO or DP Load	% of TO or DP Load
1	59.5	0.10	0.30	6.5 – 7.5	6.5 – 7.5
2	59.3	0.10	0.30	6.5 – 7.5	13.5 – 14.5
3	59.1	0.10	0.30	6.5 – 7.5	20.5 – 21.5
4	58.9	0.10	0.30	6.5 – 7.5	27.5 – 28.5
5	59.5	0.10	10.0	2 - 3	29.5 – 31.5

UFLS Table 2: Eastern Interconnection

Distribution Providers and Transmission Owners with 50 MW[2] or more and less than 100 MW[2] of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.10	0.30	14 – 25	14 – 25
2	59.1	0.10	0.30	14 – 25	28 – 50

UFLS Table 3: Eastern Interconnection

Distribution Providers and Transmission Owners with 25 MW[2] or more and less than 50 MW[2] of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.
2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

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1	59.5	0.10	0.30	28 – 50	28 – 50

Rationale Box:

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Standard PRC-006-3, R4 requires the Planning Coordinator to conduct a UFLS assessment at least once every five years. However, aside from a UFLS islanding event, it does not prescribe other factors or events which could warrant a new UFLS assessment in less than the five years time-frame.

PRC-006-NPCC-01 contained requirements if changes to load distribution impacted UFLS program performance (R21) but did not consider many other factors. The drafting team recommends retiring these requirements (R21, R22, R23) and replacing them with the following guidance.

Significant variations in the following factors could require a Planning Coordinator to conduct a new assessment:

2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

- Changes to the BES that could modify the creation of islands or the severity of events such as new transmission topologies, revised protection schemes or new or revised RAS.
- Unforeseen islanding event
- Real and reactive load distribution (including changes to location of compensatory load shedding)
- Transmission Owner or Distribution Provider's inability to implement the UFLS program within the stated tolerances
- Load characteristics in particular frequency responsive load
- Automatic load restoration
- Generation geographical distribution
- Generator trip settings
- Generation mix in particular non-BES generation that may not be subject to frequency ride-through criteria
- Generator dynamic modeling
- Dynamic VAR device modeling

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

Implementation Plan

Regional Reliability Standard PRC-006-NPCC-2 – Automatic Underfrequency Load Shedding

Applicable Standard(s)

- PRC-006-NPCC-2 – Automatic Underfrequency Load Shedding

Requested Retirement(s)

- PRC-006-NPCC-1 – Automatic Underfrequency Load Shedding

Applicable Entities

- Generator Owners
- Planning Coordinators
- Distribution Providers that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program.
- Transmission Owners that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program.

Background

The revisions to the PRC-006-NPCC-1 Automatic Underfrequency Load Shedding have been developed to address the following concerns.

1. To determine if the applicability of the standard needs to be revised in accordance with Project 2014-01 Dispersed Generation Resources.
2. To determine if the performance requirements as contained in the criteria of NPCC Directory#12 Sections 5.1.1 and 5.1.2 should be explicitly included in the requirements of the Regional Standard and potential retirement of Directory 12 Automatic Underfrequency Load Shedding Program.
3. Review Attachment C in PRC-006-NPCC-1 to address the implications of the design assessment, in accordance with Requirement R4 of PRC-006-1/PRC-006-2, of not meeting the program performance characteristics as identified in Requirement R3 of PRC-006-1/PRC-006-2.
4. Review and revise Table 4 in Attachment C in accordance with the 2013 NPCC UFLS Adequacy Assessment. Additionally, the applicability of Requirements R4 and R5 will be reviewed to consider that Hydro Quebec is not part of the Eastern Interconnection.

Effective Date

All requirements with the exception of R3 will be enforceable on the first day of the first calendar quarter following the applicable governmental and regulatory approvals.

R3 will be enforceable on the first day of the first calendar quarter 12 months following the applicable governmental and regulatory approvals.

Retirement Date

The NPCC Regional Reliability Standard PRC-006-NPCC-1 shall be retired immediately prior to the Effective Date of PRC-006-NPCC-2.

Mapping Document

Draft NPCC Regional Automatic Underfrequency Load Shedding Standard
PRC-006-NPCC-2

NPCC's regional standard PRC-006-NPCC-2 "Automatic Underfrequency Load Shedding" (UFLS) was effective in the US in July 2015. The standard is currently under revision to align with the continent-wide PRC-006-2 UFLS standard which became effective on October 2015. The draft of PRC-006-NPCC-2 removes duplicity with the continent wide standard and adds specificity to allow retirement of the NPCC UFLS Directory #12 containing more stringent UFLS performance criteria and harmonizes the requirements and criteria of all these documents.

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
PRC-006-NPCC-1 **R1** Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS). [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]	**PRC-006-NPCC-2** **R2**. Each Planning Coordinator shall provide UFLS island boundaries, as identified per the NERC continent wide PRC-006 Standard on UFLS, to Distribution Providers, Generator Owners, and Transmission Owners within 30 calendar days of receipt of a request. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]* **R3.** Each Distribution Provider and Transmission Owner in the Eastern	The purpose of R1 in PRC-006-NPCC-1 was to ensure entities that aggregate their load understand what the UFLS island boundaries are and establish criteria for compensatory load shedding. The revised R2, R3, and R13 clearly address this in the proposed PRC-006-NPCC-2.

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Interconnection portion of NPCC shall implement an automatic UFLS program, reflecting normal operating conditions, excluding outages. The automatic UFLS program shall be implemented on an island basis for each identified island per the NERC continent wide PRC-006 Standard on UFLS as follows: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]* • The UFLS program shall be implemented by each Distribution Provider and Transmission Owner according to the frequency thresholds, nominal operating times, and load shedding amounts specified in Attachment C, Tables 1-3; or • The UFLS program shall be implemented collectively by multiple Distribution Providers or Transmission Owners, as long as they reside in the same UFLS island identified by the Planning	

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Coordinator per Requirement R2. These multiple Distribution Providers or Transmission Owners, via mutual agreement, shall act as a single entity to provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load according to the frequency thresholds, total nominal operating time, and load shedding amounts specified in Attachment C, Tables 1-3. **R13.** For existing non-nuclear units in service prior to July 1, 2015, that have underfrequency protections set to trip above the appropriate curve in Figure 2: [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning*]* **13.1.** Each Generator Owner shall set the underfrequency protection to operate at the lowest frequency allowed by	

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	the plant design and licensing limitations. **13.2.** Each Generator Owner shall transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator. **13.3.** Each Planning Coordinator in Ontario, Québec and the Maritime Provinces shall arrange for compensatory load shedding, in accordance with Attachment A and as provided by a Distribution Provider or Transmission Owner, that is adequate to compensate for the loss of generator(s) due to early tripping that is within the UFLS island identified by the Planning Coordinator in Requirement R2.	

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	13.4. Each Generator Owner in the ISO-NE Planning Coordinator area and in NYISO Planning Coordinator area shall arrange for compensatory load shedding, in accordance with Attachment B and as provided by a Distribution Provider or Transmission Owner, that is adequate to compensate for the loss of generator(s) due to early tripping that is within the UFLS island identified by the Planning Coordinator in Requirement R2.	
PRC-006-NPCC-1 **R2** Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity the generation facilities within its Planning Coordinator Area	**PRC-006-NPCC-2** **R1.** Each Planning Coordinator in the Eastern Interconnection portion of NPCC shall design an UFLS program, pertaining to islands wholly within the NPCC Region, having performance	The original R2 is redundant and it is being covered by the new R1, R2 and R3.

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
necessary to support the UFLS program performance characteristics. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]	characteristics that prevents the frequency from remaining below 59.5 Hz for more than 30 seconds in accordance with Figure 1 *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]* **R2**. Each Planning Coordinator shall provide UFLS island boundaries, as identified per the NERC continent wide PRC-006 Standard on UFLS, to Distribution Providers, Generator Owners, and Transmission Owners within 30 calendar days of receipt of a request. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]* **R3.** Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program, reflecting normal operating conditions, excluding outages. The automatic UFLS program shall be implemented on an island basis for each identified island per	

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	the NERC continent wide PRC-006 Standard on UFLS as follows: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]* • The UFLS program shall be implemented by each Distribution Provider and Transmission Owner according to the frequency thresholds, nominal operating times, and load shedding amounts specified in Attachment C, Tables 1-3; or • The UFLS program shall be implemented collectively by multiple Distribution Providers or Transmission Owners, as long as they reside in the same UFLS island identified by the Planning Coordinator per Requirement R2. These multiple Distribution Providers or Transmission Owners, via mutual agreement, shall act as a single entity to provide an aggregated	

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	automatic UFLS program that sheds their coincident peak aggregated net Load according to the frequency thresholds, total nominal operating time, and load shedding amounts specified in Attachment C, Tables 1-3	
PRC-006-NPCC-1 **R3** Each Planning Coordinator shall provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1. [Violation Risk Factor: Low] [Time Horizon: Long Term Planning]	**PRC-006-NPCC-2** **R2**. Each Planning Coordinator shall provide UFLS island boundaries, as identified per the NERC continent wide PRC-006 Standard on UFLS, to Distribution Providers, Generator Owners, and Transmission Owners within 30 calendar days of receipt of a request. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]* **R13.** For existing non-nuclear units in service prior to July 1, 2015, that have underfrequency protections set to trip above the appropriate curve in Figure	The reliability intent of Version 1 R3 was to ensure that the entities aggregating load were aware of the island boundaries. This is covered in draft R2 of the proposed revision to the standard. Requirements regarding compensatory load shedding have been clarified and are covered through draft R13.

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	2: [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning*]* **13.1.** Each Generator Owner shall set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations. **13.2.** Each Generator Owner shall transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator. **13.3.** Each Planning Coordinator in Ontario, Québec and the Maritime Provinces shall arrange for compensatory load shedding, in accordance with Attachment A and as provided by a Distribution Provider or Transmission Owner, that is	

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	adequate to compensate for the loss of generator(s) due to early tripping that is within the UFLS island identified by the Planning Coordinator in Requirement R2. **13.4.** Each Generator Owner in the ISO-NE Planning Coordinator area and in NYISO Planning Coordinator area shall arrange for compensatory load shedding, in accordance with Attachment B and as provided by a Distribution Provider or Transmission Owner, that is adequate to compensate for the loss of generator(s) due to early tripping that is within the UFLS island identified by the Planning Coordinator in Requirement R2.	
PRC-006-NPCC-1 **R4** Each Distribution Provider and Transmission Owner in the Eastern	**PRC-006-NPCC-2** **R4.** Each Distribution Provider or Transmission Owner in the Eastern	Added clarity and combined with the original R4 and R5 into one requirement.

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Interconnection portion of NPCC shall implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3, or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3. [Violation Risk Factor: High] [Time Horizon: Long Term Planning	Interconnection portion of NPCC that does not meet the UFLS program parameters specified in Attachment C, Table 1-3, and each Distribution Provider or Transmission Owner in the Quebec Interconnection that does not meet the UFLS program parameters specified by its Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]* • Within 30 calendar days of determining that it does not meet the specified parameters, notify its Planning Coordinator that it does not meet the UFLS program parameters; and • Within the following 180 calendar days from notification of the Planning Coordinator, (1) develop a Corrective Action Plan and a schedule for implementation that is mutually agreed upon with its Planning Coordinator or (2) provide its Planning Coordinator with a technical study that demonstrates that the deviations from the program parameters will	

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	not result in failure of UFLS performance criteria being met for any island. The technical study must be acceptable to the Planning Coordinator prior to implementing deviations from program parameters and shall demonstrate coordination with UFLS programs of all entities residing within the same island(s) identified by the Planning Coordinator in Requirement R2. The technical study shall also demonstrate coordination with other UFLS programs of adjoining Planning Coordinators, or (3) provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3	

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
PRC-006-NPCC-1 **R5** Each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on its total peak net Load shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning] **5.1** Inform its Planning Coordinator of the need to exceed the stated tolerances or the number of stages as shown in UFLS Attachment C, Table 1 if applicable and **5.2** Provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the bulk power system.	**PRC-006-NPCC-2** **R4.** Each Distribution Provider or Transmission Owner in the Eastern Interconnection portion of NPCC that does not meet the UFLS program parameters specified in Attachment C, Table 1-3, and each Distribution Provider or Transmission Owner in the Quebec Interconnection that does not meet the UFLS program parameters specified by its Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]* • Within 30 calendar days of determining that it does not meet the specified parameters, notify its Planning Coordinator that it does not meet the UFLS program parameters; and • Within the following 180 calendar days from notification of the Planning Coordinator, (1) develop a Corrective Action Plan and a schedule for implementation that is mutually agreed upon with its Planning Coordinator or	Added clarity and combined with the original R4 and R5 into one requirement.

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
5.3 Inform its Planning Coordinator of the need to exceed the stated tolerances of UFLS Attachment C, Table 2 or Table 3, and in the case of Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and **5.4** Provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3.	(2) provide its Planning Coordinator with a technical study that demonstrates that the deviations from the program parameters will not result in failure of UFLS performance criteria being met for any island. The technical study must be acceptable to the Planning Coordinator prior to implementing deviations from program parameters and shall demonstrate coordination with UFLS programs of all entities residing within the same island(s) identified by the Planning Coordinator in Requirement R2. The technical study shall also demonstrate coordination with other UFLS programs of adjoining Planning Coordinators, or (3) provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or	

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3	
PRC-006-NPCC-1 **R6** Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]		The drafting team agreed to retire the requirement because it is redundant to the Quebec Variance section of the PRC-006-3 NERC standard.

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
PRC-006-NPCC-1 **R7** Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with the following minimum time delay: 7.1 Eastern Interconnection – 100 ms 7.2 Québec Interconnection – 200 ms [Violation Risk Factor: High] [Time Horizon: Long Term Planning]	**PRC-006-NPCC-2**	The drafting team agreed to retire the requirement because the time delay is added into Attachment C tables.
PRC-006-NPCC-1 **R8** Each Planning Coordinator shall develop and review once per calendar year settings for inhibit thresholds (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]	**PRC-006-NPCC-2** **R5.** Each Planning Coordinator shall develop and review settings for inhibit thresholds at least once per five calendar years (such as, but not limited to, voltage, current and time) to be utilized within its region's UFLS program. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*	Periodicty of develop and review settings has been increased from once per calendar year to once per five calendar years. This coincides with the the periodicity of UFLS studies. Having a yearly "develop and review" without taking any further action is strictly administrative and does nothing for reliability (P-81 type of issue).

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
NPCC-006-NPCC-1 **R9** Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]	**NPCC-006-NPCC-2** **R6.** Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 calendar days of any changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*	Clarified the language.
NPCC-006-NPCC-1 **R10** Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R9. [Violation Risk Factor: High] [Time Horizon: Operations Planning]	**NPCC-006-NPCC-2** **R8.** Each Distribution Provider and Transmission Owner shall implement the inhibit thresholds provided by the Planning Coordinator in accordance with Requirement R6 and based on the Planning Coordinator approved implementation plan in accordance with R7. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*	Only made changes to requirement numbers referenced only. Added clarification for Planning Coordinator developes implementation plan.

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
NPCC-006-NPCC-1 **R11** Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R9. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]	**PRC-006-NPCC-2** **R7.** Each Distribution Provider and Transmission Owner that receives a notification pursuant to Requirement R6 shall develop and submit an implementation plan with respect to inhibit thresholds for approval by the Planning Coordinator within 90 calendar days of the request from the Planning Coordinator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*	Language clarifications and changes to requirement numbers referenced.
PRC-006-NPCC-1 **R12** Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays.	**PRC-006-NPCC-2** **R9.** Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 calendar months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage. The actual net Load shall be coincident with the entity's integrated hourly peak net Load during the previous year, as determined by	Added language that allows calculation of load from nearest available metering rather than actual metering. The requirement as it exists is placing undo burden to install metering when it can be accurately calculated as a cost effective alternative.

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]	measuring or calculating Load through the switches that would disconnect load if triggered by the UFLS relays. If measured data is unavailable then calculated data may be used. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*	
PRC-006-NPCC-1 **R13** Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R16 and R19. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]	**PRC-006-NPCC-2** **R10.** Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, on or below the appropriate generator underfrequency trip protection setting threshold curve in Figure 2, except as otherwise exempted in Requirements R13 and R16. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*	Clarification was made that the Underfrequency trip relay must to be set to operate "on or below" the appropriate curve. In Version 1 it currently states below and questions arose whether settings on the curve were considered in compliance.
NPCC-006-NPCC-1 **R14** Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request.	**PRC-006-NPCC-2** **R11.** Each Generator Owner shall transmit the generator underfrequency trip setting and time delay within 45 calendar days of the Planning Coordinator's request. *[Violation Risk*	No Change from Version 1 only requirement numbering

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
[Violation Risk Factor: High] [Time Horizon: Operations Planning]	*Factor: Lower] [Time Horizon: Operations Planning]*	
PRC-006-NPCC-1 **R15** Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net capability by greater than 10% shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning] **15.1** Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1. **15.2** Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip	**PRC-006-NPCC-2** **R12.** Each Generator Owner with a new generating unit, or an existing generator increasing its net capability by greater than 10% shall: *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]* **12.1.** Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 2. **12.2.** Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the	Removed language pertaining to the Version 1 of the standard regarding on or after the effective date. Version 1 has been in place and transition/implementation concerns need not be addressed in this requirement.

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
protection settings threshold curve in Figure 1.	generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection setting threshold curve in Figure 2.	
PRC-006-NPCC-1 **R16** Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning] **16.1** Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations. **16.2** Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.	**PRC-006-NPCC-2** **R13.** For existing non-nuclear units in service prior to July 1, 2015, that have underfrequency protections set to trip above the appropriate curve in Figure 2: [Violation Risk Factor: High] [Time Horizon: Long Term Planning*]* **13.1.** Each Generator Owner shall set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations. **13.2**. Each Generator Owner shall transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical	Addition made to R13.3 and R13.4 which is the approved requirement R16 to clarify that any compensatory load shedding must be in the island the generating unit resides in.

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
16.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.	basis for the settings to the Planning Coordinator. **13.3.** Each Planning Coordinator in Ontario, Québec and the Maritime Provinces shall arrange for compensatory load shedding, in accordance with Attachment A and as provided by a Distribution Provider or Transmission Owner, that is adequate to compensate for the loss of generator(s) due to early tripping that is within the UFLS island identified by the Planning Coordinator in Requirement R2. **13.4.** Each Generator Owner in the ISO-NE Planning Coordinator area and in NYISO Planning Coordinator area shall arrange for compensatory load shedding, in accordance with Attachment B and as provided by a Distribution Provider or Transmission Owner, that is adequate to compensate	

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	for the loss of generator(s) due to early tripping that is within the UFLS island identified by the Planning Coordinator in Requirement R2.	
PRC-006-NPCC-1 **R17** Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]	**PRC-006-NPCC-2** **R14.** Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R13.3 for generating units in its respective NPCC area. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*	Only made changes to the requirement number.
PRC-006-NPCC-1 **R18** Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in	**PRC-006-NPCC-2** **R15.** Each Generator Owner, Distribution Provider or Transmission Owner within the ISO-NE Planning Coordinator area and in NYISO Planning Coordinator Area shall apply the criteria described in Attachment B to determine the compensatory load shedding that is	Only made changes to the requirement number.

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]	required in Requirement R13.4 for generating units in its respective NPCC area. *[Violation Risk Factor: High][Time Horizon: Long Term Planning]*	
PRC-006-NPCC-1 **R19** Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 1, based on their licensing design basis, shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning] **19.1** Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8Hz. **19.2** Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz. **19.3** Transmit the initial frequency trip setting and any changes to the setting and the	**PRC-006-NPCC-2** **R16.** Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 2 based on their licensing design shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]* **16.1.** Set the underfrequency protection to operate at a frequency as low as possible in accordance with the plant design and licensing limitations but not greater than 57.8 Hz. **16.2.** Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.	Only made changes to the requirement number and Figure reference update.

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
technical basis for the settings to the Planning Coordinator.	**16.3.** Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.	
PRC-006-NPCC-1 **R20** The Planning Coordinator shall update its UFLS program database as specified by the NERC PRC Standard on UFLS. This database shall include the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning] **20.1** For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings. **20.2** The buses at which the Load is modeled in the NPCC library power flow case. **20.3** A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency	**PRC-006-2 (Existing in force continent-wide standard)** **R6.** Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessment of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. [VRF: Lower][Time Horizon: Long-term Planning]	The drafting team decided to remove requirement 19 and 20 because they are covered by the continent-wide PRC-006-2 requirement 6. The requirement 19 and 20 language will be transferred over to new guideline document.

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system. **20.4** The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping. **20.5** A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.		
PRC-006-NPCC-1 **R21** Each Planning Coordinator shall notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]	**PRC-006-2 (Existing in force continent-wide standard)** **R3.** Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance =	PRC-006-NPCC-1 R21 is now redundant with the NERC continent wide standard R3. This requirement, R21 is proposed for retirement under the P-81 criteria.

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	[(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). [VRF: High][Time Horizon: Long-term Planning] **3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and **3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and **3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer	

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following: • Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES • Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES • Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.	
PRC-006-NPCC-1 **R22** Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the	**PRC-006-2 (Existing in force continent-wide standard)** **R9.** Each UFLS entity shall provide automatic tripping of Load in accordance with the	PRC-006-NPCC-1 R22 is now redundant with the NERC continent wide standard R9 and this requirement, R22 is proposed for retirement under the P-81 criteria.

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
notification provided by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]	UFLS program design and schedule for implementation, including any Corrective Action Plan, as determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. [VRF: High][Time Horizon: Long-term Planning]	
PRC-006-NPCC-1 **R23** Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]	**PRC-006-2 (Existing in force continent-wide standard)** **R3.** Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). [VRF: High][Time Horizon: Long-term Planning]	PRC-006-NPCC-1 states an implemention plan for changes needs to be submitted to the PC for their approval within 90 days of the request. However in R22 of the regional standard it states that the changes shall be implemented based on the PC's notification. We believe this is fully covered in R3 and an additional implementation plan beyond the PC's plan, which includes the notification and schedule for the UFLS entities to follow is now unnecessary in the regional standard. We are recommending that R23 in the regional standard be retired.

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and **3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and **3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus	

Standard: PRC-006-NPCC-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	associated with each of the following: • Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES • Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.	

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November 2, 2018

VIA EMAIL

Regional Standards Committee (RSC)
NPCC
rscmembers@npcc.org

Subject: PRC-006-NPCC-02 Automatic Underfrequency Load Shedding – Approval to Post for Pre-Ballot and Ballot Period

Dear RSC Members:

The PRC-006-NPCC-2 Automatic Underfrequency Load Shedding Regional Standard has been posted for three 45-day comment periods. The drafting team has responded to every comment from all three periods. NPCC's Manager of Reliability Standards has posted all comment responses onto the NPCC website. The next step, in accordance with the NPCC Regional Standard Processes Manual, is to obtain the RSC's approval to post for a 30-day pre-ballot review period and a subsequent 10-day ballot period. If you have not already done so, please email your approval to Mr. Ruida Shu so he can post the documents for pre-ballot and ballot period.

I'd like to take this opportunity to commend all the members of the Standard Drafting Team, and those who supported them, for their perseverance through the arduous task of re-writing this Regional Standard over the course of the past two years and five months. Their dedication was essential to accomplish the team's mission.

If you have any questions, please don't hesitate to contact me.

Regards

Dan Taft
Chief Engineer – Control Systems Engineering Department
Chair – NPCC PRC-006-NPCC-2 Standard Drafting Team

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Northeast Power Coordinating Council, Inc. Directory Development and Revision Manual

&

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

Redlined to Cost Effectiveness Revisions
November 5, 2018



~~August 23, 2018~~

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	10/26/2011	Effective Date	New
1	12/5/2013	Revised	Revised Interpretation Approval Process
2	10/03/2014	Revised	Added NPCC CEAP Considerations
3	8/23/2018	Revised	Added Process for Review and Approval of Criteria, Guides, and procedures from Document A-01 to permit retirement of A-01
4		Revised	Revise the Cost Effectiveness Assessment procedure, specify identification of incremental reliability benefit

I. CONTENTS

II. EXECUTIVE SUMMARY 4

III. BACKGROUND 5

III. APPLICABILITY OF NPCC CRITERIA 6

IV. TASK FORCE ROLES AND RESPONSIBILITIES 6

V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE 7

1. NEW DIRECTORY 7

2. DIRECTORY REVISIONS 14

a. Revisions to the Criteria Section of a Directory 14

b. Revisions to the Appendix Section of a Directory 20

c. Revisions To The NPCC Glossary Of Terms 25

d. Withdrawal Of Revision Requests 29

3. DIRECTORY RETIREMENT 30

4. MAINTENANCE OF LINKS AND ERRATA 30

VI. DIRECTORY CLARIFICATION PROCESS 31

a. Request for Criteria Clarification 31

B. APPEALS 34

VII. DIRECTORY FORMAT AND VERSION CONTROL 34

VIII. NPCC PROCEDURE FOR COST EFFECTIVE ANALYSIS OF PROPOSED AND REVISED CRITERIA IN DIRECTORIES 34

IX. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES 35

X. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL & PROCESS FOR THE REVIEW AND APPROVAL OF CRITERIA, GUIDELINES, AND PROCEDURES 41

APPENDIX A - DIRECTORY FORMAT TEMPLATE 42

APPENDIX B – NPCC REQUEST FOR CLARIFICATION 46

~~II. EXECUTIVE SUMMARY ..... 3~~

~~III. BACKGROUND ..... 3~~

~~III. APPLICABILITY OF NPCC CRITERIA ..... 5~~

~~IV. TASK FORCE ROLES AND RESPONSIBILITIES ..... 5~~

~~V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE ..... 6~~

~~1. NEW DIRECTORY ..... 6~~

~~2. DIRECTORY REVISIONS ..... 9~~

~~*a. Revisions to the Criteria Section of a Directory ..... 9*~~

~~*b. Revisions to the Appendix Section of a Directory ..... 12*~~

~~*c. Revisions To The NPCC Glossary Of Terms ..... 14*~~

~~*d. Withdrawal Of Revision Requests ..... 17*~~

3. DIRECTORY RETIREMENT 17
4. MAINTENANCE OF LINKS AND ERRATA 17
VI. DIRECTORY CLARIFICATION PROCESS 18
a. *Request for Criteria Clarification* 18
b. APPEALS 21
VII. DIRECTORY FORMAT AND VERSION CONTROL 21
VIII. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES 21
IX. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL & PROCESS FOR THE REVIEW AND APPROVAL OF CRITERIA, GUIDELINES, AND PROCEDURES 26
APPENDIX A - DIRECTORY FORMAT TEMPLATE 27
APPENDIX B – NPCC REQUEST FOR CLARIFICATION 31

II. EXECUTIVE SUMMARY

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

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

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

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

Accordingly, ~~aspects of the~~ ~~the fundamental review methodology of the~~ an evaluation of the ~~NPCC Cost Effectiveness Analysis Procedure (CEAP)~~ ~~for the development of Regional Standards has have~~cost effectiveness of achieving the incremental reliability benefit has been incorporated into the~~i~~is Directory Development and Revision Manual and appears in Section VIII.

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

III. BACKGROUND

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

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

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

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

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

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

Most of NPCC's "B" Guideline and "C" Procedure documents were transferred to Directories as Appendices in support of the relevant criteria. Those B and C documents that were not incorporated into a Directory remain as standalone documents. ~~Phase 2 work has been completed.~~

Further work on the individual Directories~~y documents~~ will emphasize the importance of ~~specifically~~ identifying the specific incremental reliability benefit provided by the criteria ~~improvement~~ beyond the NERC Standards and if any cost effective alternatives exist or were considered. This additional work will be done during the normal course of development or review ~~the revision process~~ by the Task Force responsible for the ~~at particular~~ Directory.

III. APPLICABILITY OF NPCC CRITERIA

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

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

IV. TASK FORCE ROLES AND RESPONSIBILITIES

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

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

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

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

The Lead Task Force will also consider the cost effectiveness of the proposed criteria within the Directory during each periodic review of the document or for any proposed revisions to the criteria. Cost Effectiveness Analysis (CEA) activities will be conducted as outlined in Section VIII and will

~~The Cost Effectiveness Analysis (CEA) of the criteria will consist of~~ utilize survey questions developed by the Task Force to accompany ~~an initial~~ the open process comment period(s). These questions will be designed to solicit Member comment on whether the ~~e~~Criteria represents an incremental benefit to reliability and whether there are any cost effective alternatives to achieving a similar or greater level of reliability. As noted in Section VIII, the Lead Task Force may waive the cost effectiveness portion of the review or conduct it any time during the development process. In all cases, the Lead Task Force will document its cost effectiveness ~~related~~ decisions and activities. The Lead Task Force may choose to waive the cost effective analysis portion of the development process if it is deemed to be of no added value (e.g. no change to established beneficial criteria or how to achieve the reliability objective). In this case, a letter from the Task Force Chair indicating the desire of the ~~the~~ Task Force is to waive the CEA will be sent to the RCC and RSC to be stored with the developmental record.

V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE

1. NEW DIRECTORY

~~Any NPCC Full Member may request the development of a new Directory. The request shall be made to the NPCC Manager of Reliability Criteria via email and shall contain the background and justification for the development of the new Directory as well as any potential costs of implementation information that may be available.~~

~~The NPCC Manager of Reliability Criteria shall forward the request for the development of a new Directory, along with a request for the RSC to authorize a Cost~~

Effectiveness Analysis utilizing the NPCC CEAP procedure to the Regional Standards Committee (RSC). The RSC will review the request and assign the request to develop a new Directory to the appropriate Task Force (TF) and copy the Regional Standards Committee (RSC) and the Reliablity Coordinating Committee (RCC). The Lead Task Force responsible for developing the new Directory shall review the request and all information submitted, preferably with the potential cost of implementation information, and determine if the development activity is warranted. If the TF accepts the request, it will develop a recommendation for the RCC. draft an initial version of the document consistent with the Directory template in Attachment A.

The RSC working with NPCC Staff shall utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed Directory via the Cost Benefit Analysis (CBA) section of the CEAP. The RCC will review the TF recommendation and conclude whether the new Directory should move forward based on its incremental reliability benefit and cost of implementation. If

In accordance with the CBA section of the CEAP if the RSCC concludes that the development of a new Directory is not cost effective for the potential incremental reliability benefit, the RSCC will direct the TF to draft an initial version of the document consistent with the Directory template in Attachment A with assistance from the , forward the results of the CBA to the Manager of Reliability Criteria. The Manager of Reliability Criteria will provide for notification of acceptance to develop the new Directory toto the Lead Task Force and the requesting NPCC Full Member.

After the RSC reviews and approves theUpon development of the new draft DirectoryCBA the Lead Task Force shall post the draft Directoryit to the NPCC Open Process for a 45 days comment period.

At the conclusion of the 45-day Open Process period, the Lead Task Force will discuss the comments submitted, develop responses and revise the Directory if necessary. The Lead Task Force shall also determine if the Cost Effectiveness Analysis (CEA) portion of the CEAP cost effectiveness activities shall begin be conducted, document their CEA activities, such as survey results, and where appropriate, request and provide any necessary notifications to the RSCC to initiate the CEA.

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

~~The RSCC in accordance with the CEAP will use the responses to the any CEA cost effectiveness survey(s) to develop any further recommendations based on the cost effectiveness offor the proposed Directory. After the RCC approves both the draft Directory, and thein consideration of CEAP cost effectiveness and reliability benefit, the draft Directory is then submitted for ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.~~[1]

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

Any NPCC Full Member may request the development of a new Directory. The request shall be made to the NPCC Manager of Reliability Criteria and shall contain the background and justification for the development of the new Directory including a cost effectiveness assessment if available.

The NPCC Manager of Reliability Criteria shall forward the request for the development of a new Directory, to the appropriate Task Force (TF) and copy the Regional Standards Committee (RSC) and the Reliability Coordinating Committee (RCC). The Lead Task Force responsible for developing the new Directory shall review the request and all information submitted, including any cost effectiveness documentation and determine if the development activity is warranted. If the TF accepts the request, it will notify the RCC of its intent to develop a new Directory and conduct a Cost Effectiveness Analysis (CEA) in accordance with Section VIII of the Directory Manual to accompany the initial posting of the draft Directory.

Upon development of the new draft Directory the Lead Task Force shall post it to the NPCC Open Process for a 45 day comment period. The initial posting will include the cost effective survey questions as contained in Section VIII.

At the conclusion of the 45-day Open Process period, the Lead Task Force will consider comments received, develop responses to the comments and revise the Directory if necessary. The Lead Task Force shall also evaluate and document the results of the cost effectiveness survey questions.

The Lead Task Force will present the draft Directory along with the results of the cost effective analysis to the RCC.

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

The RCC will review the TF recommendation and conclude whether the new Directory should move forward for Full Member consideration based on its incremental reliability benefit and cost effectiveness.

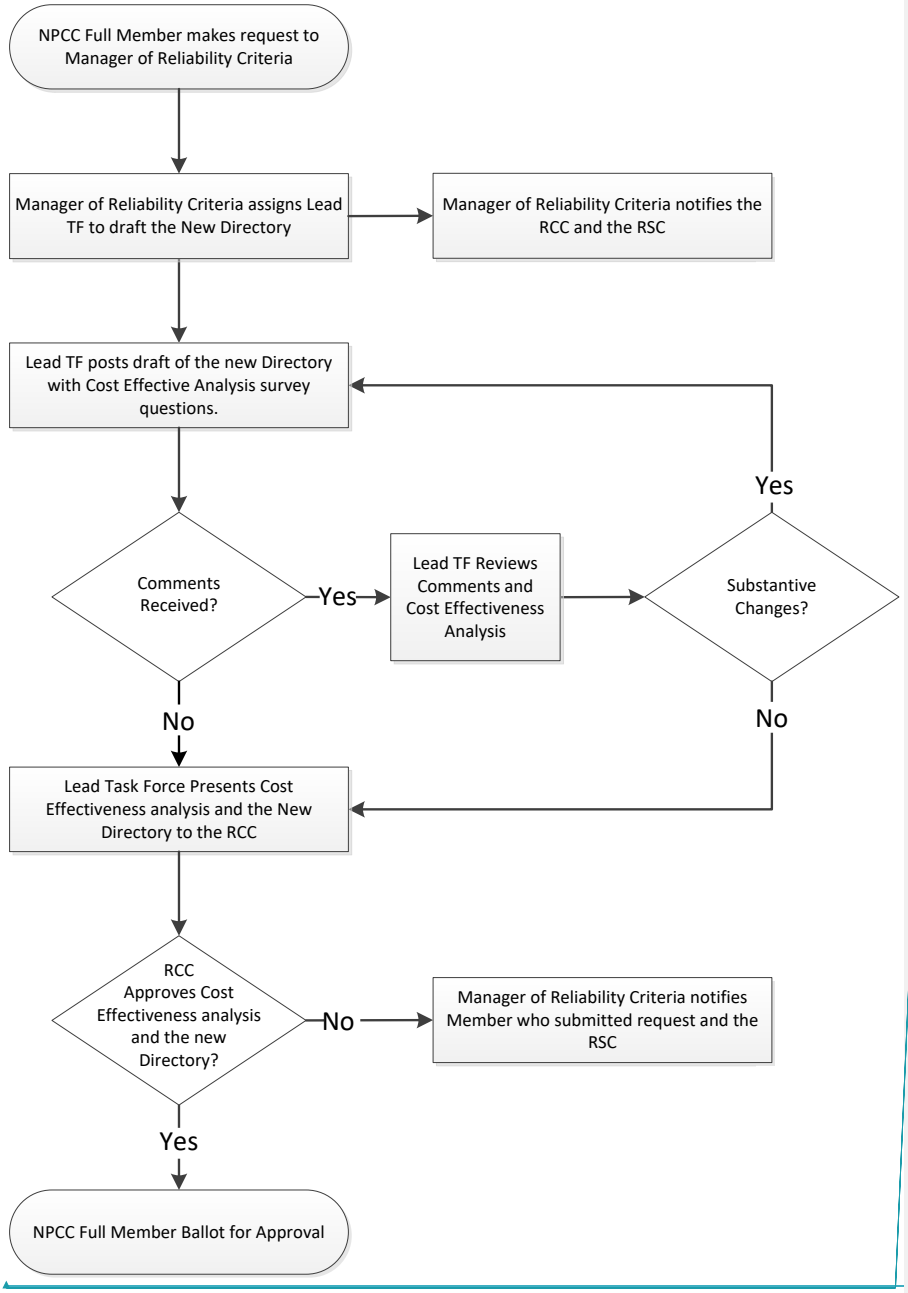
If the RCC concludes that the development of a new Directory is not cost effective, the RCC will notify the Manager of Reliability Criteria for notification to the RSC, the Lead Task Force and the NPCC Full Member that submitted the request to develop a new Directory.

After consideration of cost effectiveness and reliability benefit if the RCC approves the draft Directory it is then submitted for final approval by the NPCC Full Member Representatives along with the RCC recommendation of approval.[2]

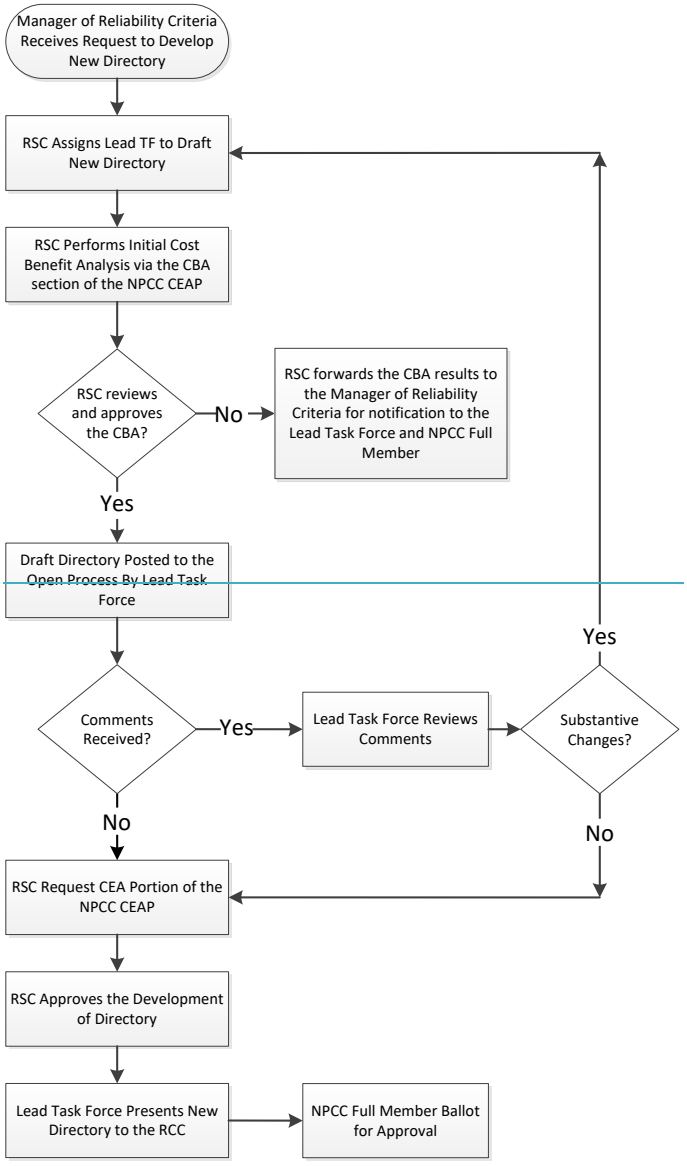
The process for establishing a new Directory is represented below in Figure 1:

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

Figure 1: New Directory



Field Code Changed


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

2. DIRECTORY REVISIONS

a. REVISIONS TO THE CRITERIA SECTION OF A DIRECTORY

The Lead Task Force can initiate a full revision of the Directory in accordance with the NPCC Reliability Assessment Program (NRAP) date of approval or some need to revise the criteria section of the document as determined by a Full Member, the Lead Task Force itself or due to revision of a NERC Standard.

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

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

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

~~In accordance with the CBA section of the CEAP if the RSC concludes that the revision to an existing Directory is not cost effective the RSC will forward the results of the CBA to the Manager of Reliability Criteria for notification to the Lead Task Force and NPCC Full Member.~~

The Lead Task Force shall review the request to revise the criteria and shall also consider conforming changes to appendices as a result of the criteria revision if necessary.

The Lead Task Force will also consider the cost effectiveness of the criteria within the Directory during each periodic review of the document or for any proposed revisions to the criteria.

The cost effectiveness of the criteria will consist of CEA survey questions developed by the Task Force and which are designed to solicit Member comment on the relative cost of different approaches to achieving the level of reliability provided by the criteria. Emphasis will ~~also~~ be placed on identification of the incremental reliability benefit of the criteria ~~proposed by the Directory~~ beyond ~~above~~ that which may be achieved by any associated NERC Standards.

These survey questions will accompany the Open Process 45 day posting of the Directory in order to promote transparency.

~~The Cost Benefit Analysis section of the NPCC Cost Effectiveness Analysis Procedure (CEAP)~~Section VIII provides guidance for ~~this analysis~~the CEA and Open Process posting. If the Lead Task Force determines that there is no benefit to conducting the CEA activity then this decision shall be documented and notification provided to the RCC and RSC along with the reasons for the decision to waive this portion of the process.

The NPCC Manager of Reliability Criteria shall post the Directory containing the revised criteria to the NPCC Open Process review for 45 days, along with the survey questions developed to assess the cost effectiveness of the criteria. ~~.~~ The survey responses will be documented and archived as part of the record of the Task Force review.

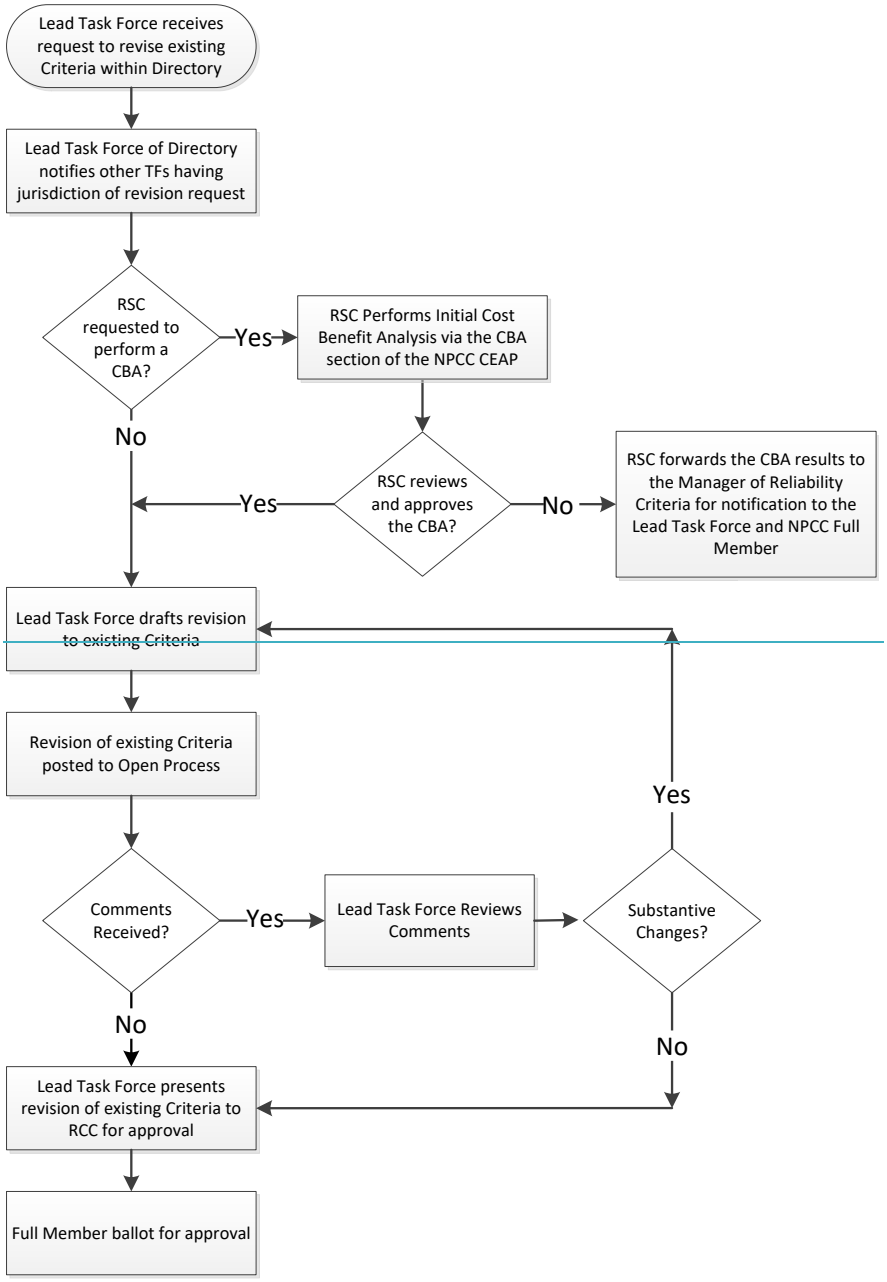
At the conclusion of the 45-day Open Process, the Lead Task Force will discuss the comments submitted and post responses to comments on the NPCC Open Process portal. If the responses to the comments received on the criteria revision result in substantive changes to the document, then the revised Directory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

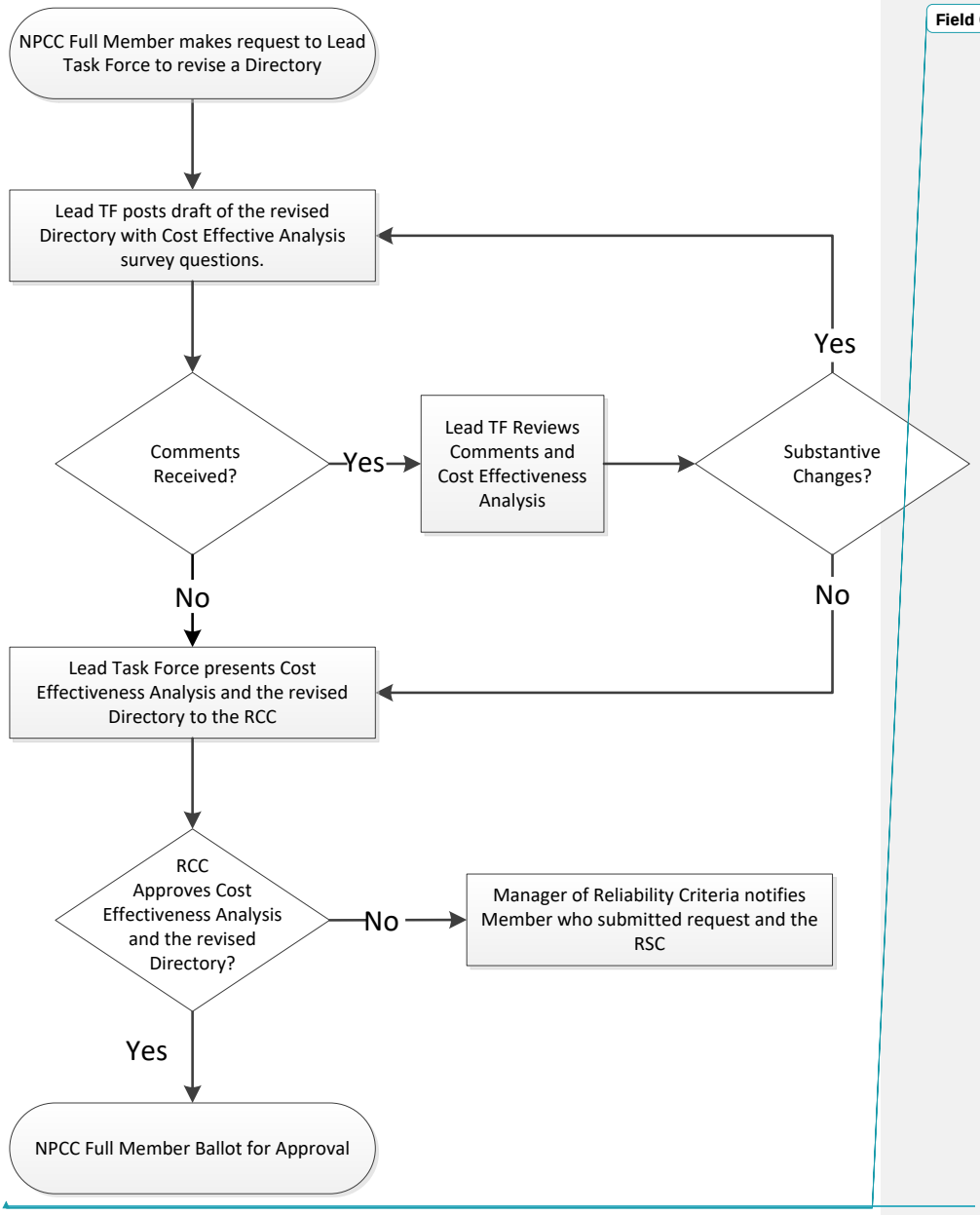
Alternatively, if there are no substantive changes which would require additional postings, the Directory is presented to the Reliability Coordinating Council (RCC) for approval along with any information regarding incremental reliability benefit and cost effectiveness. Upon RCC approval, the document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

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

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

Figure 2: Revisions to Criteria


Lead Task Force receives request to revise existing Criteria within Directory
Lead Task Force of Directory notifies other TFs having jurisdiction of revision request
RSC requested to perform a CBA?
Yes
RSC Performs Initial Cost Benefit Analysis via the CBA section of the NPCC CEAP
No
RSC reviews and approves the CBA?
Yes
No
RSC forwards the CBA results to the Manager of Reliability Criteria for notification to the Lead Task Force and NPCC Full Member
Lead Task Force drafts revision to existing Criteria
Revision of existing Criteria posted to Open Process
Comments Received?
Yes
Lead Task Force Reviews Comments
Substantive Changes?
Yes
No
No
Lead Task Force presents revision of existing Criteria to RCC for approval
Full Member ballot for approval



Field Code Changed

b. REVISIONS TO THE APPENDIX SECTION OF A DIRECTORY

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

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

The Lead Task Force of the Directory shall be responsible for notifying all Task Forces which have jurisdiction over either the criteria or one or more of the other Appendices within the Directory that a request to revise, add or retire an appendix has been received. The Lead Task Force ~~at this time~~ will also determine whether to waive or conduct cost effective activities associated with the proposed revisions to the Appendix and notify the RCC and RSC of such determination.

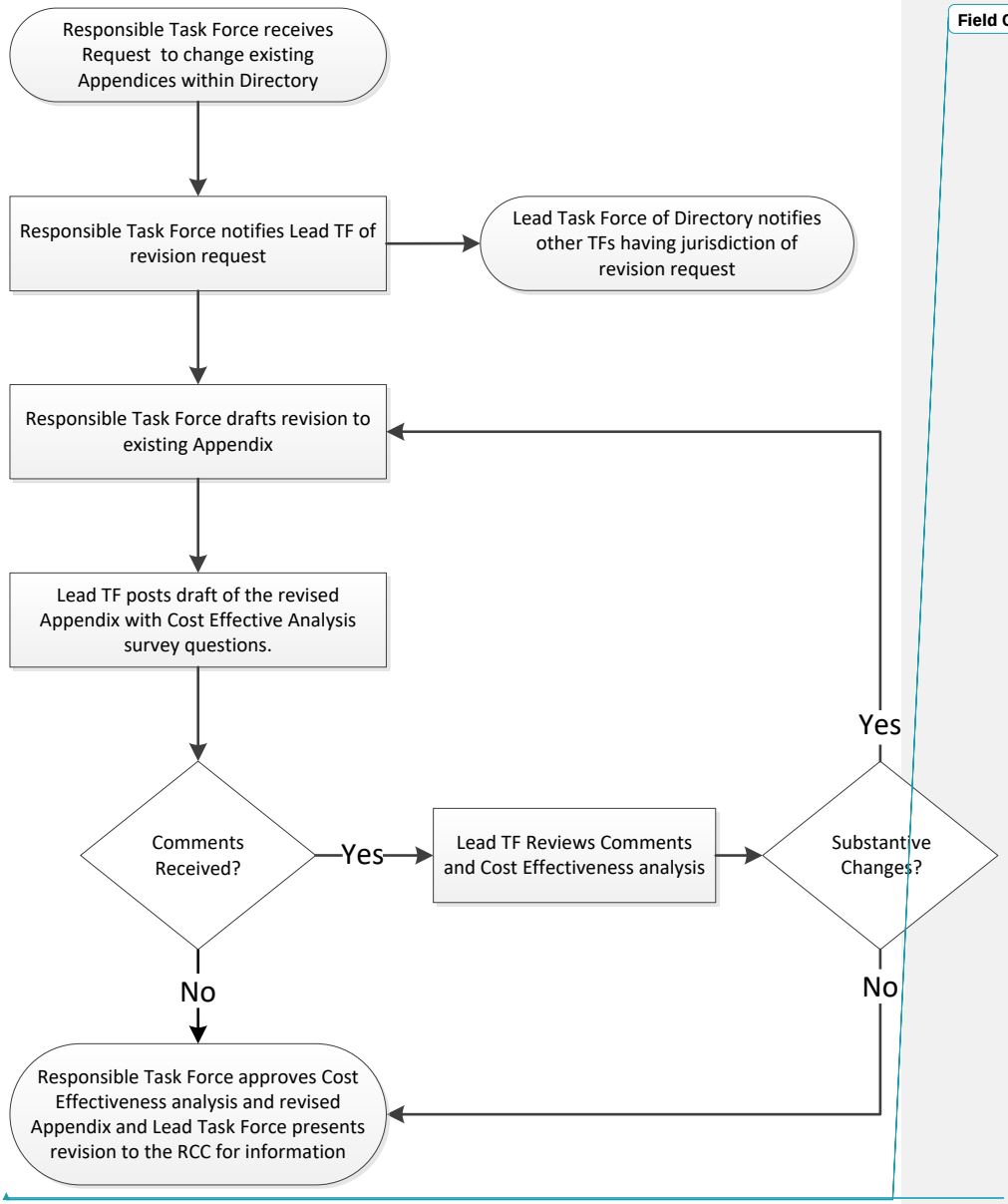
After the Task Force responsible for the revised Appendix request reviews the subject Appendix, they will forward the Directory containing the draft revised Appendix to the Lead Task Force of the Directory. The Lead Task Force shall be responsible for posting the Directory (in its entirety) which contains the new, revised, or retired Appendix to the NPCC Open Process review for 45 days and will also conduct the cost effectiveness activities as described ~~noted~~ in Section VIII if ~~as may be~~ necessary. The Lead Task Force will limit the comments solicited to only the subject Appendix.

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

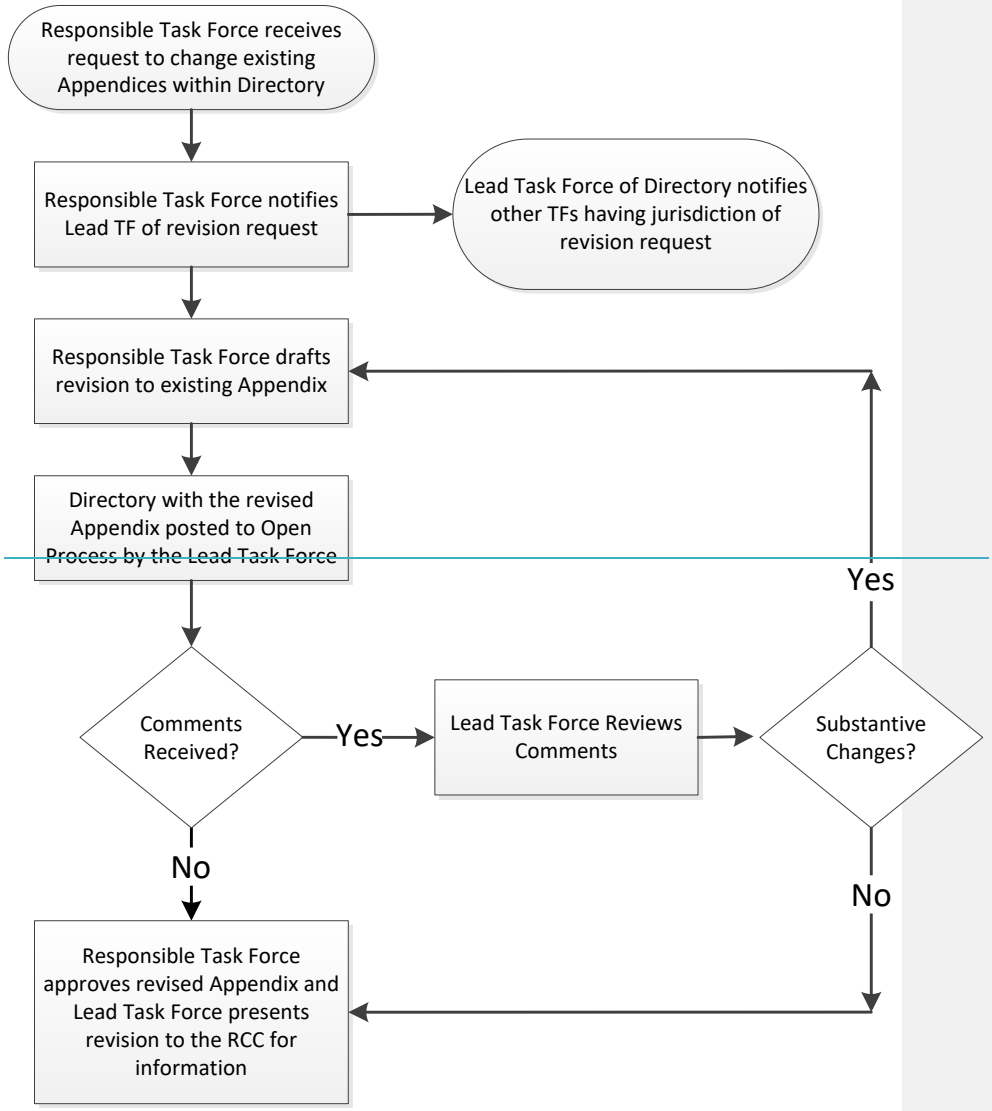
The lead Task Force for the Directory containing the new, revised or retired Appendix shall distribute the Directory containing the revised or retired Appendix to the RCC~~eliability Coordinating committee~~ for informational purposes.

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

Figure 3: Revisions to Appendices



Field Code Changed


Responsible Task Force receives request to change existing Appendices within Directory
Responsible Task Force notifies Lead TF of revision request
Lead Task Force of Directory notifies other TFs having jurisdiction of revision request
Responsible Task Force drafts revision to existing Appendix
Directory with the revised Appendix posted to Open Process by the Lead Task Force
Comments Received?
Yes
Lead Task Force Reviews Comments
Substantive Changes?
Yes
No
No
Responsible Task Force approves revised Appendix and Lead Task Force presents revision to the RCC for information

c. REVISIONS TO THE NPCC GLOSSARY OF TERMS

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

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

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

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

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

In general, it is not anticipated that the development of a new or revised term in the Glossary will result in significant cost implications. However, the NPCC Manager of Reliability Criteria may request the ~~RSC~~ Lead Task Force to utilize the ~~NPCC CEAP~~cost effectiveness activities as described in Section VIII ~~to perform an initial analysis of the cost~~ effectivenessbenefit ~~via the Cost Benefit Analysis (CBA) section of the CEAP~~ to identify cost impact and reliability benefit of the proposed or revised Glossary term.

The R~~S~~C will review the results of the ~~CBA~~ cost effectiveness activities conducted for ~~review of~~ the proposed or revised Glossary term with the Lead Task Force and the

NPCC Manager of Reliability Criteria prior to the Task Force proceeding with the process of establishing a new or revised Glossary term.

In accordance with Section VIII, ~~the CBA section of the CEAP~~ if the RCS~~S~~C concludes that the development of a new or revised Glossary term is not cost effective, the R~~S~~SCC will forward the ~~results of the CBA~~determination to the Manager of Reliability Criteria for notification to the Lead Task Force and NPCC Full Member.

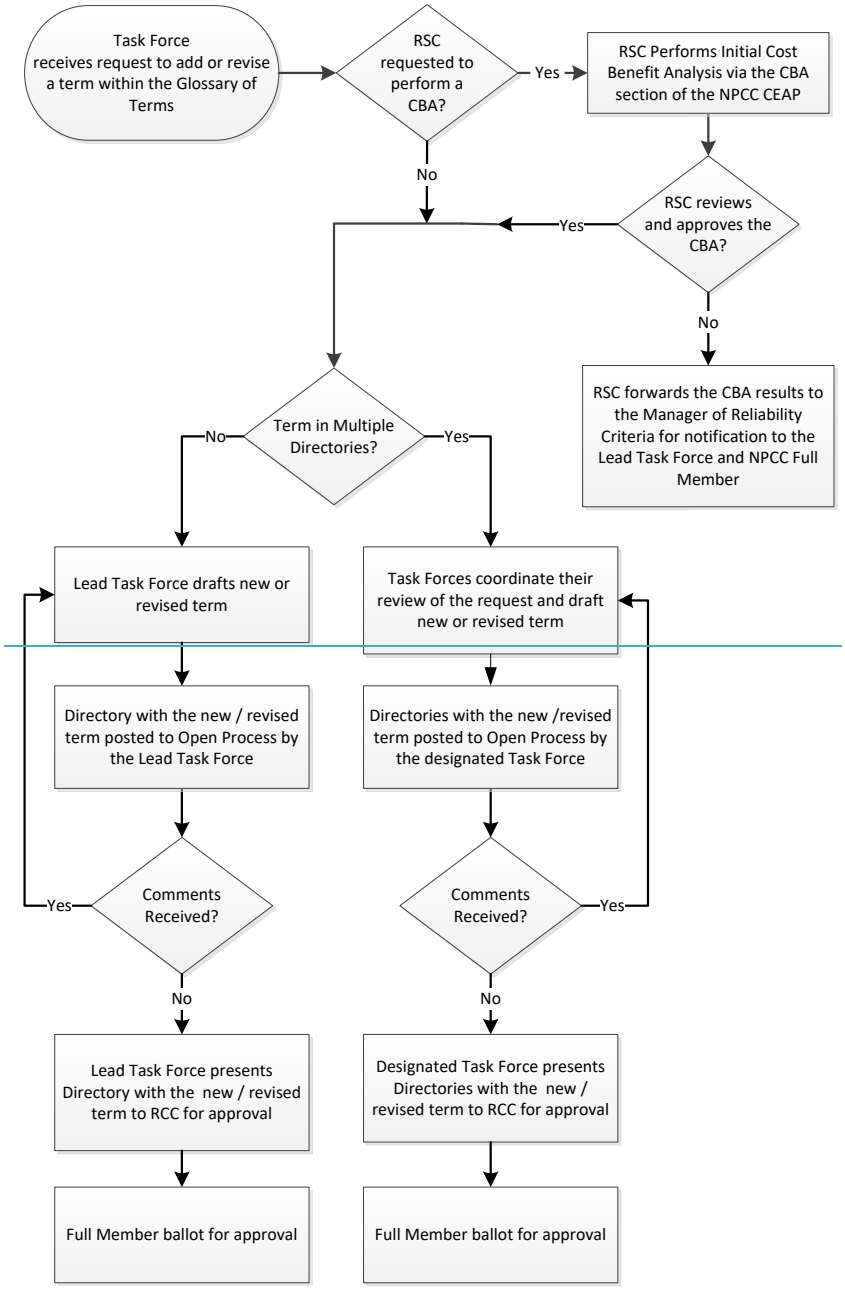
After the Lead Task Force, in which the defined term resides, has completed its review, they will post the subject Directory containing the new or revised term to the NPCC Open Process for 45 days. When the new or revised term appears in multiple Directories, the designated Lead Task Force for the review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

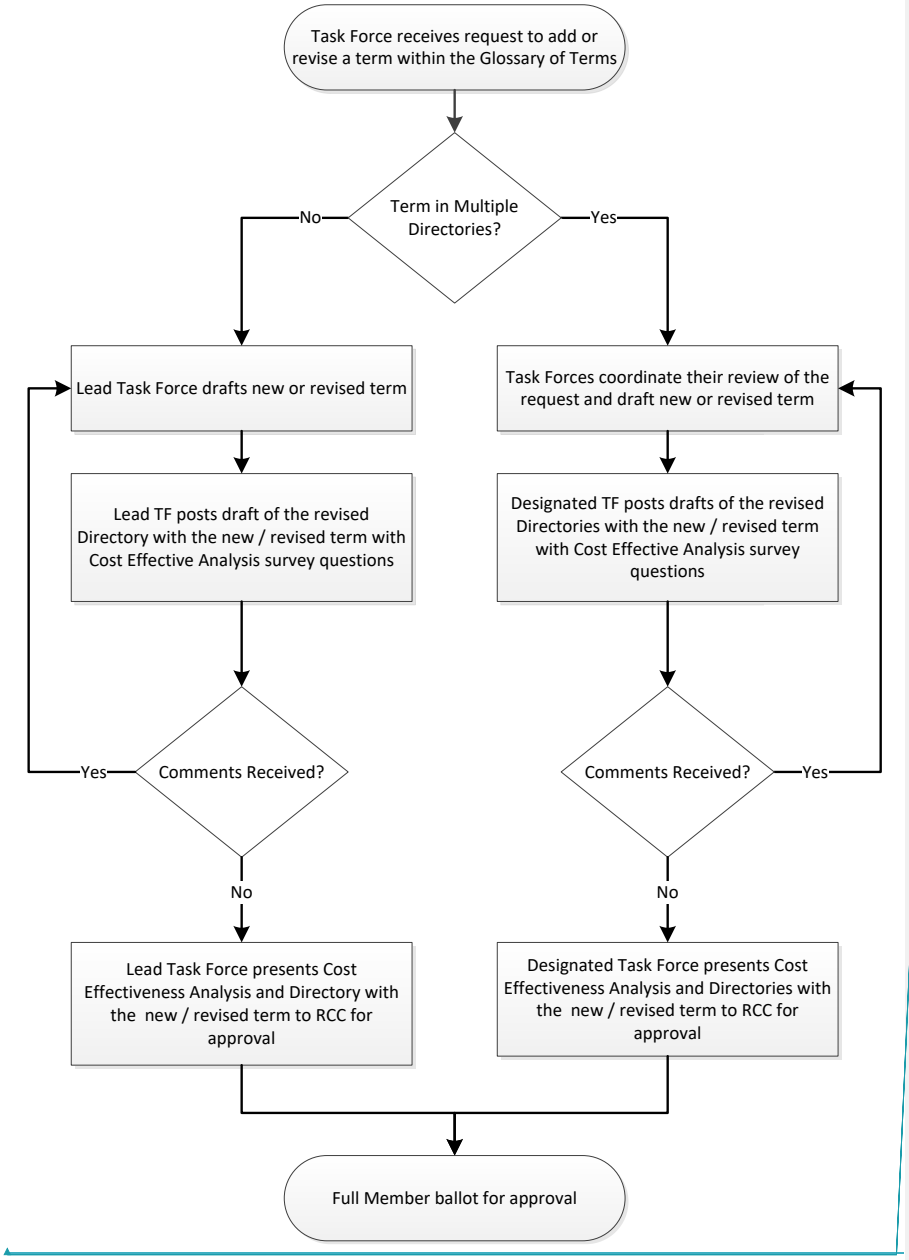
At the conclusion of the 45-day Open Process, if responses to comments received on the new or revised term result in further substantive change to the term, then the Directory containing the new or revised term shall be reposted to the Open Process for a successive 45 day posting period by the Lead Task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

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

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

Figure 4: Revisions to the NPCC Glossary of Terms


Task Force receives request to add or revise a term within the Glossary of Terms
RSC requested to perform a CBA?
Yes
RSC Performs Initial Cost Benefit Analysis via the CBA section of the NPCC CEAP
No
RSC reviews and approves the CBA?
Yes
No
RSC forwards the CBA results to the Manager of Reliability Criteria for notification to the Lead Task Force and NPCC Full Member
Term in Multiple Directories?
No
Yes
Lead Task Force drafts new or revised term
Task Forces coordinate their review of the request and draft new or revised term
Directory with the new / revised term posted to Open Process by the Lead Task Force
Directories with the new /revised term posted to Open Process by the designated Task Force
Comments Received?
Yes
No
Comments Received?
Yes
No
Lead Task Force presents Directory with the new / revised term to RCC for approval
Designated Task Force presents Directories with the new / revised term to RCC for approval
Full Member ballot for approval
Full Member ballot for approval



Field Code Changed

d. WITHDRAWAL OF REVISION REQUESTS

Any NPCC Full Member which has initiated a request to develop a new Directory, revise an existing Directory or revise an NPCC Glossary Term may withdraw the request at any time prior to Full Member approval of the revised Directory or NPCC Glossary Term by notifying the NPCC Manager of Reliability Criteria. The NPCC Manager of Reliability Criteria will then notify the Lead Task Force, RSC and RCC.

3. DIRECTORY RETIREMENT

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

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

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

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

4. MAINTENANCE OF LINKS AND ERRATA

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

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

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

VI. DIRECTORY CLARIFICATION PROCESS

a. REQUEST FOR CRITERIA CLARIFICATION

Any NPCC Full Member may request a clarification of the criteria within a Directory. The NPCC Full Member seeking the clarification shall submit a ***Request for Criteria Clarification*** form [3] to the NPCC Manager of Reliability Criteria explaining the clarification required and the specific circumstances surrounding the request. The NPCC Manager of Reliability Criteria shall review the request and work with the originator to make certain that the request is clearly written, seeks clarity regarding the intent or purpose of the criteria and is not a question on a compliance aspect of the criteria.

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

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

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

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

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

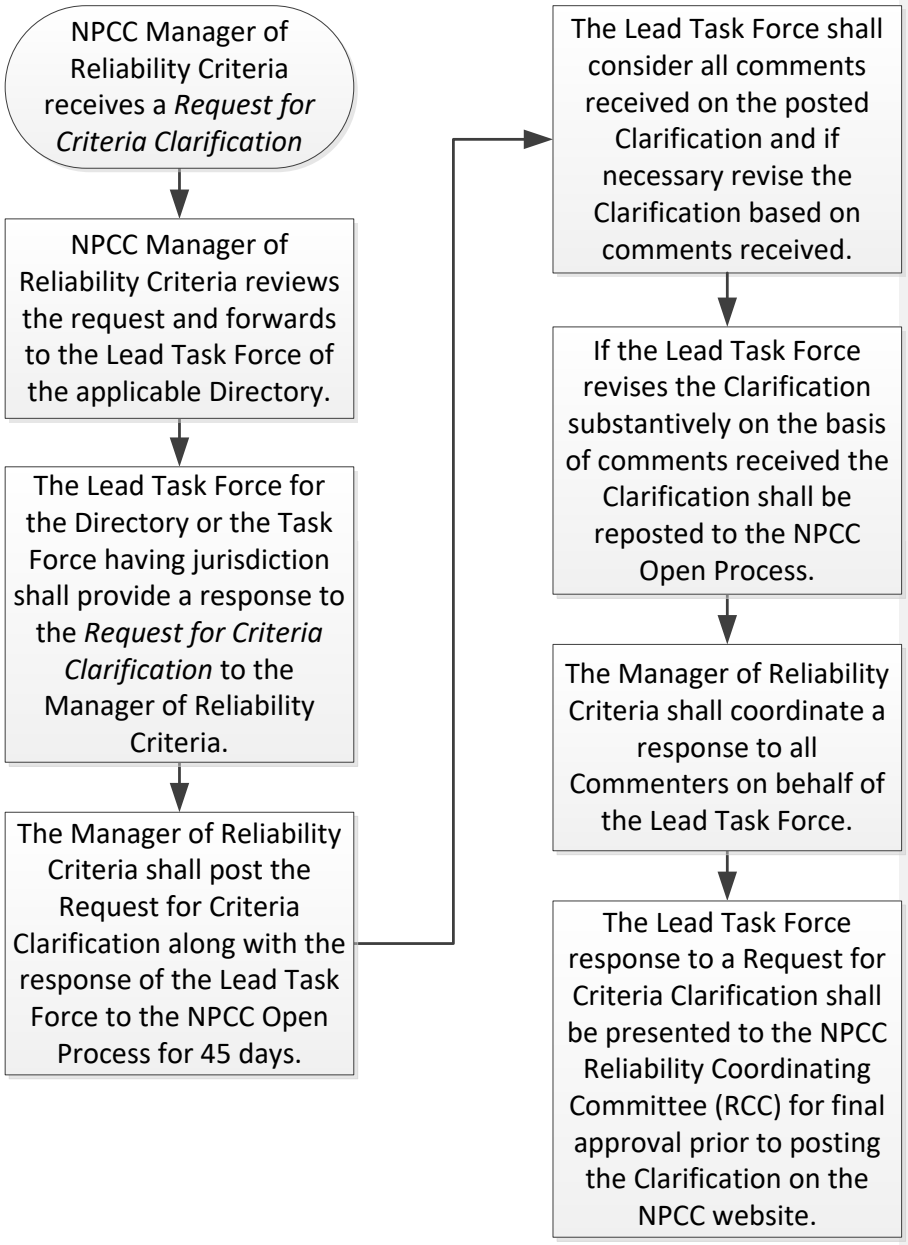
The NPCC Manager of Reliability Criteria shall review the clarification provided by the Lead Task Force or the Task Force having jurisdiction to ensure that it is clear and provides the requested explanation without expanding on the criteria.

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

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

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

Figure 5: Request for Criteria Clarification



b. APPEALS

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

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

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

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

VII. DIRECTORY FORMAT AND VERSION CONTROL

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

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

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

VIII. NPCC PROCEDURE FOR COST EFFECTIVE ANALYSIS (CEA) OF NEW ~~PROPOSED~~ AND REVISED CRITERIA IN DIRECTORIES

1. Upon receipt of a request to review or revise the criteria in an existing Directory, by a~~n~~ NPCC Full Member, or a request to develop a new Directory, the Task Force having jurisdiction (Lead Task Force) will determine if the activity warrants conducting cost effectiveness activities.

2. The Lead Task Force will document these activities as part of the record of development and notify the RCC and RSC of intent to conduct cost effectiveness activities or exercise a waiver.

3. If the Task Force later determines that conducting cost effectiveness activities is warranted at any time during the development process of the new or revised Directory, the Task Force will notify the NPCC Manager of Reliability Criteria.

4. NPCC will coordinate the necessary cost effective activities as directed by the Task Force. These activities will focus on identification of the incremental reliability benefit of the Criteria and the ~~implementation cost and~~ cost effectiveness associated with that benefit. The Lead Task Force shall use the subject matter expertise of its M~~m~~embers as well as other TFs, as may be applicable, along with the Open Process 45 day posting(s) for comment to gather this information (See below for sample questions).

- Does the proposed Criteria provide ~~address~~ an increased level ~~or benefit~~ of reliability?~~ which is necessary to protect NPCC's reliability?~~ If not, why not (probabilistic data, such as the information taken from the Reliability Issues Steering Committee report(s) regarding probable occurrence of a risk may be used to help make a determination)~~?~~
- ~~What approximate implementation and ongoing estimated potential costs would be associated with compliance with the proposed Criteria?~~
- Is there a more cost effective solution to achieving the same or greater level of reliability?~~ if a different approach was taken?~~ If so what is that solution?
- How long would it take your organization to implement full compliance to the Criteria as written? What would affect the implementation (i.e. outage scheduling, availability of materials, human resources, etc.)?

5. The Task Force shall use the information obtained, to make a determination if the revised or new Criteria is of sufficient reliability benefit to pursue further development activities by NPCC or if other cost effective approaches to achieve the reliability objective of the Criteria should be pursued. (e.g. development of a whitepaper, guideline document, etc.)

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

Introduction

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

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

Document, Criteria - Type "A"

General Description

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

Review and Approval

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

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

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

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

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

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

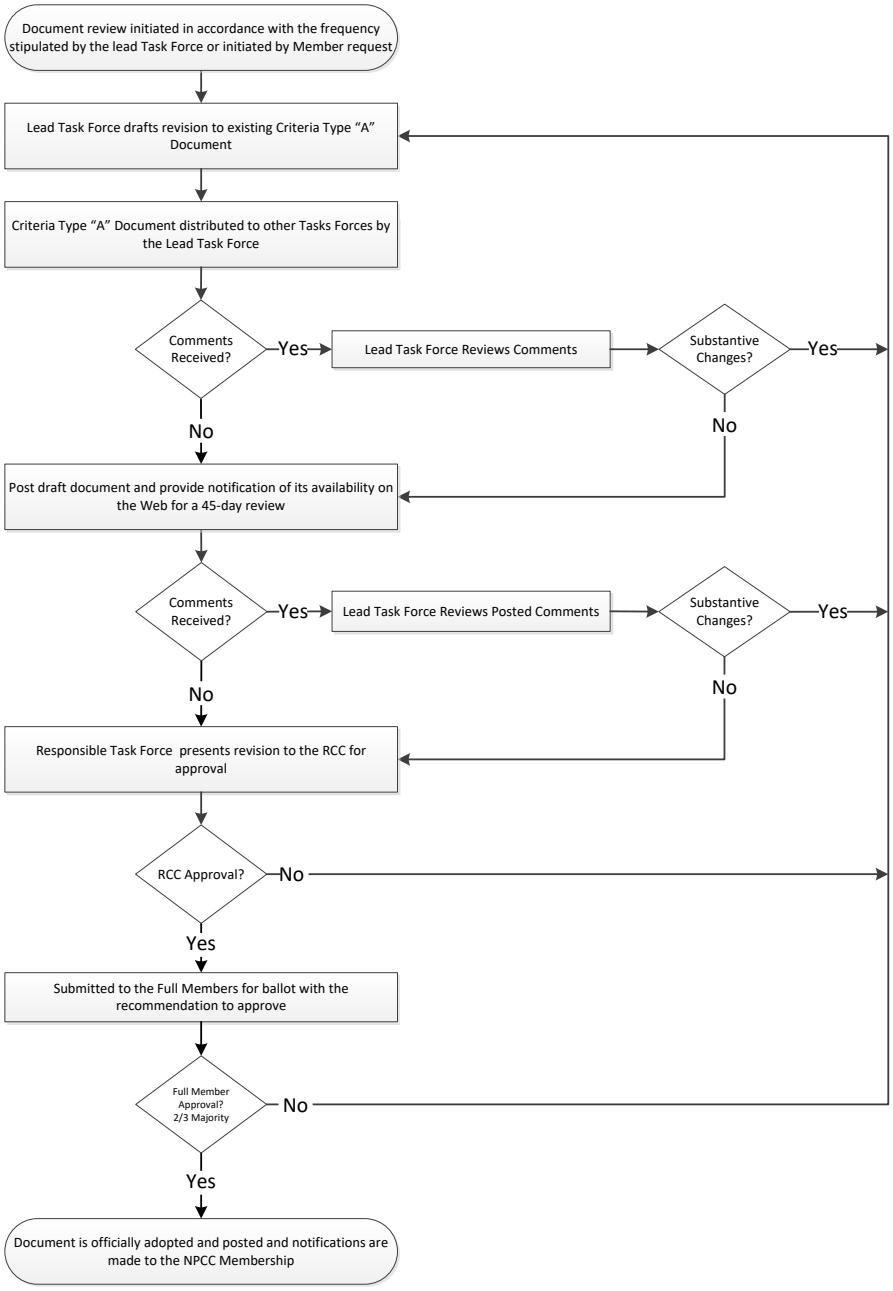
The approved and adopted Type “A” document will then be posted, along with necessary additional documentation, if needed, such as an implementation plan or schedule for achieving full compliance with the requirements outlined in the document. This will be posted on the NPCC web site and distributed to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

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

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

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

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



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

General Description

Type "B" documents are guideline documents.

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

Review and Approval

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

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

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

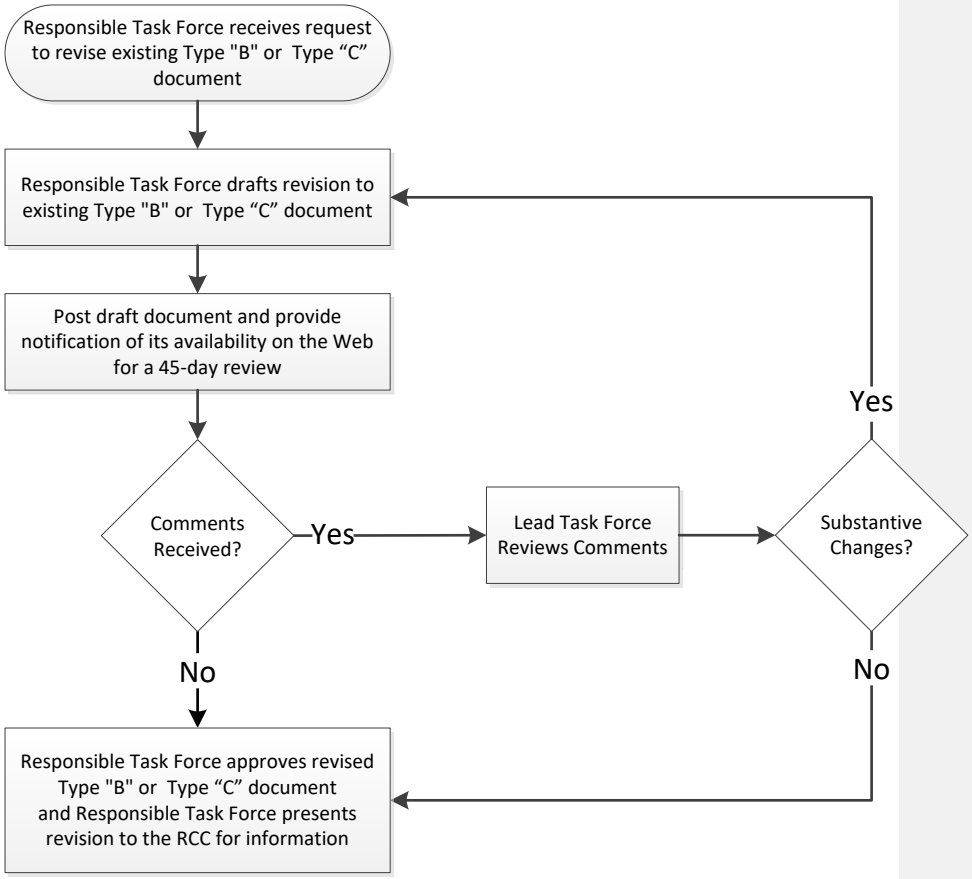
The revised B or C document (or the proposal to retire a B or C document) shall be posted to the NPCC Open Process for a 45-day posting.

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

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

The process for revisions to an existing Type "B" and "C"document is represented below in Figure 7:

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



X. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL & PROCESS FOR THE REVIEW AND APPROVAL OF CRITERIA, GUIDELINES, AND PROCEDURES

The NPCC Directory Development and Revision Manual & Process for the Review and Approval of Criteria, Guidelines, and Procedures will be reviewed at least once every five (5) years or more frequently if required.

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

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

APPENDIX A - DIRECTORY FORMAT TEMPLATE



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

NPCC
Regional Reliability Reference Directory # XX

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

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

Revision History

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

Format for NPCC Directories (Phase 2)

Effective Dates (Denotes date of adoption by the Membership)

Revision History (Depicts revision history and tracks key changes)

Table of Content (Self-explanatory)

A. Introduction

Title: Self-explanatory

Directory #: Self-explanatory

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

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

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

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

B. NERC ERO Reliability Standard Requirements

A list of the NERC standards associated with this Directory.

C. NPCC Regional Reliability Standard Requirements

A list of NPCC Regional Standards associated with this Directory.

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

Requirements

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

E. Compliance

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

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

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

APPENDIX B – NPCC REQUEST FOR CLARIFICATION



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

NPCC Request for Criteria Clarification

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

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

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

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

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RC11-6-000**

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION'S ANNUAL REPORT ON THE FIND, FIX, TRACK AND REPORT AND COMPLIANCE EXCEPTION PROGRAMS

November 1, 2018

TABLE OF CONTENTS

I. INTRODUCTION **1**

II. THE FFT AND CE PROGRAMS HAVE BEEN SUCCESSFULLY IMPLEMENTED AND HAVE CONTINUED TO EVOLVE SINCE INCEPTION. **3**

III. JOINT NERC AND FERC ANNUAL REVIEW OF THE FFT AND CE PROGRAMS **6**

IV. ONGOING NERC REVIEWS OF NONCOMPLIANCE AND RELATED PROCESSES **8**

V. CONCLUSION **9**

APPENDIX A. Methodology and Criteria Applied in FFT and CE Sampling **10**

APPENDIX B. Specific Analysis of the Sampled Issues **13**

A. Process documents 13

B. Description of the issue and risk assessment 14

C. Evaluation and documentation of mitigation activities 15

ATTACHMENT 1. Process Review Checklist **17**

I. INTRODUCTION

The North American Electric Reliability Corporation (NERC), as the Electric Reliability Organization (ERO),[1] respectfully submits this report on the Find, Fix, Track and Report (FFT) and Compliance Exception (CE) programs. This filing complies with the Federal Energy Regulatory Commission's (FERC or the Commission) March 15, 2012 Order,[2] June 20, 2013 Order,[3] and September 18, 2014 Order[4] requiring an annual report on NERC's FFT program. This filing also combines the evaluation of CEs with the annual sampling of FFTs in compliance with the Commission's November 13, 2015 Order.[5]

Since 2011, the ERO Enterprise[6] has used the FFT program to resolve over 2,400 instances of noncompliance with the NERC Reliability Standards, 90.69% of which posed a minimal risk to the reliability of the bulk power system (BPS).[7] Since June 2013, the ERO Enterprise has used the FFT program to resolve noncompliance posing a moderate risk to the BPS. The Commission agreed that the FFT program has "produced efficiencies in NERC's processing of compliance and enforcement matters" and that continuing to use the FFT program

[1] The Commission certified NERC as the ERO in accordance with section 215 of the Federal Power Act on July 20, 2006. *North American Electric Reliability Corp.*, 116 F.E.R.C. ¶ 61,062 (2006), *order on reh'g and compliance*, 117 F.E.R.C. ¶ 61,126 (2006), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 342 (D.C. Cir. 2009).

[2] *North American Electric Reliability Corp.*, 138 F.E.R.C. ¶ 61,193 (2012) [hereinafter March 15 Order].

[3] *North American Electric Reliability Corp.*, 143 F.E.R.C. ¶ 61,253 (2013) [hereinafter June 20 Order].

[4] *North American Electric Reliability Corp.*, 148 F.E.R.C. ¶ 61,214 (2014) [hereinafter September 18 Order].

[5] *North American Electric Reliability Corp.*, Letter Order Accepting NERC's Annual Report on the Find, Fix, Track & Report Program, Docket No. RC11-6-004 (FERC Nov. 13, 2015) [hereinafter November 13 Order].

[6] The term "ERO Enterprise" refers to NERC and the seven Regional Entities. The seven Regional Entities are Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst (RF), SERC Reliability Corporation (SERC), Texas Reliability Entity (Texas RE), and Western Electricity Coordinating Council (WECC). NERC and FERC staff agreed to exclude the Southwest Power Pool Regional Entity (SPP RE) from the survey, reducing the burden on SPP RE as it focused efforts on a planned and approved termination of its responsibilities as a Regional Entity.

[7] NERC's searchable public FFT, CE, and Spreadsheet Notice of Penalty spreadsheets, and full Notices of Penalty, are available on NERC's Enforcement and Mitigation website. *See Enforcement & Mitigation*, NORTH AMERICAN ELECTRIC RELIABILITY CORP., https://www.nerc.com/pa/comp/CE/Pages/Enforcement-and-Mitigation.aspx (last visited August 22, 2018).

to address moderate risk issues will result in a "more efficient enforcement process and allow NERC and the Regional Entities to focus on occurrences of severe risk violations."[8]

Building on the success of the FFT program, the ERO Enterprise developed the CE program in February 2014 to streamline further the resolution of lesser-risk noncompliance with NERC Reliability Standards. The ERO Enterprise has resolved over 2,500 instances of noncompliance posing a minimal risk to the BPS through CEs since the inception of that program.[9]

In 2018, NERC and Commission staff completed their annual joint coordinated review of FFTs and CEs and found that the ERO Enterprise appropriately handles noncompliance posing a minimal or moderate risk through these programs.[10] NERC and Commission staff agreed with the final risk determinations for almost all FFTs and CEs sampled, and noted a significant improvement in the clear identification of root cause over the last four years.[11] Commission staff also agreed with NERC that the FFT and CE programs are meeting expectations.

[8] *North American Electric Reliability Corp.*, 148 F.E.R.C. ¶ 61,214 at PP 1, 35.

[9] *See supra* n.7.

[10] *See North American Electric Reliability Corp.*, 143 F.E.R.C. ¶ 61,253 (2013); *see also North American Electric Reliability Corp.*, 148 F.E.R.C. ¶ 61,214 (2014); *North American Electric Reliability Corp.*, Letter Order Accepting NERC's Annual Report on the Find, Fix, Track and Report Program, Docket No. RC11-6-004 (FERC Nov. 13, 2015); *North American Electric Reliability Corp.*, Letter Order Accepting NERC's Annual Report on the Find, Fix, Track and Report Program, Docket No. RC11-6-005 (FERC Jan. 13, 2017); *North American Electric Reliability Corp.*, Notice of Staff Review of Compliance Programs, Docket No. RC11-6-005 (FERC June 27, 2017); *North American Electric Reliability Corp.*, Order Accepting the Compliance Monitoring and Enforcement Program, Docket No. 15-2-005 (FERC Nov. 16, 2017).

[11] *See infra* Appendix B.

II. THE FFT AND CE PROGRAMS HAVE BEEN SUCCESSFULLY IMPLEMENTED AND HAVE CONTINUED TO EVOLVE SINCE INCEPTION

The FFT and CE programs are important elements of the ERO Enterprise's risk-based approach to enforcement.[12] The FFT program resolves noncompliance posing a minimal or moderate risk to the reliability of the BPS, while the CE program resolves noncompliance posing a minimal risk outside of Section 5.0 of the Compliance Monitoring and Enforcement Program (CMEP). Both programs require: (a) mitigation of the noncompliance; (b) availability of the facts and circumstances of the noncompliance for review by NERC and Applicable Governmental Authorities; (c) tracking and analysis of the noncompliance as necessary to identify broader risks; and (d) providing the opportunity for the registered entity to opt out.[13] These programs have streamlined processing, reduced caseload, and helped to ensure the efficient resolution of minimal and moderate risk noncompliance.

The FFT program was the first major step in implementing a risk-based approach to the enforcement of Reliability Standards that recognizes the fact that not all instances of noncompliance require the same type of processing and documentation. Over the last seven years, the FFT program evolved from a processing track limited to minimal risk noncompliance to a vehicle for the efficient and effective disposition of moderate risk noncompliance. The success of the FFT program in resolving lesser risk noncompliance led to the development of the CE program and the expansion of the FFT program to include resolution of moderate risk issues.

[12] For a description of NERC's enforcement processes, CEs, and FFTs, *see* NERC Rules of Procedure, App. 4C §§ 3.8, 3A.0, 3A.1, & 5.2A, respectively, available at https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/NERC_ROP_Effective_20180719.pdf.

[13] *See* NERC Rules of Procedure, App. 4C §§ 5.2A, 3A, respectively.

The ERO Enterprise used these programs to resolve 82% of all discovered noncompliance in the first half of 2018.[14]

Registered entities and Regional Entities have experienced efficiency gains due to the reduced documentation required for FFTs and CEs.[15] As of Q2 2018, 66% of the noncompliance inventory across all Regional Entities is less than one year old, and only 3% is over two years old.[16] There are only three pre-2014 instances of noncompliance still remaining to be processed.[17]

Because of successive improvements to the FFT program – particularly the extension to moderate risk noncompliance in 2013 – NERC and the Regional Entities are able to resolve minimal and moderate risk noncompliance efficiently and effectively, thereby allowing them to focus their resources on noncompliance posing a greater risk to the reliability of the BPS.[18] The ERO Enterprise's use of the FFT and CE programs has continued to increase since FERC initially approved them. For example, the percentage of noncompliance resolved through FFT increased from 21% of moderate risk noncompliance in 2015 to 45% in 2018 through Q2 2018.[19]

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[14] *See* North American Electric Reliability Corp., *Compliance Monitoring & Enforcement Program Report: Second Quarter 2018*, Appendix A: Enforcement, Figure A.5 at 13 (Aug. 15, 2018), https://www.nerc.com/gov/bot/BOTCC/Compliance%20Committee%202013/Compliance%20Committee%20Open%20Meeting%20-%20August%2015%202018.pdf.

[15] *See North American Electric Reliability Corp.*, NERC's Compliance Filing and Report on the Compliance Enforcement Initiative and Proposed Enhancements to the FFT Program, Docket No. RC11-6-004, at 9 (FERC Mar. 15, 2013).

[16] *See supra* n.14, Appendix A: Enforcement, Figure A.1 at 10.

[17] *Id*.

[18] *See North American Electric Reliability Corp.*, 148 F.E.R.C. ¶ 61,214 at PP 1, 25, n.37; *see also North American Electric Reliability Corp.*, NERC's Annual Report on the Find, Fix, Track, and Report Program, Docket No. RC11-6-004, at 2 (Sept. 18, 2015); *North American Electric Reliability Corp.*, NERC's Annual Report on the Find, Fix, Track, and Report and Compliance Exception Programs, Docket No. RC11-6-005, at 2 (FERC Jan. 13, 2017); *see also North American Electric Reliability Corp.*, NERC's Annual Report on the Find, Fix, Track and Report Compliance Exception Programs, Docket No. RC11-6-000, at 1-2 (FERC Oct. 4, 2017).

[19] *See supra* n.7.

In addition, the ERO Enterprise used CEs to resolve 91.6% of the minimal risk noncompliance in 2017,[20] and 87.6% in 2018 through Q2 2018.[21]

The effective use of streamlined processing for lower risk noncompliance, through the CE and FFT programs, preserves ERO Enterprise resources for higher risk issues. Using CEs and FFTs to resolve minimal and moderate risk noncompliance means that violations posing a more significant risk continue to receive the most attention and resources through processing in spreadsheet Notices of Penalty (NOPs) or full NOPs. Spreadsheet and full NOPs are used to resolve the highest risk violations, and accordingly the ERO Enterprise prioritizes these disposition methods with the greatest level of focus. Among those highest risk cases was a full NOP NERC filed in February 2018, resolving two violations of Critical Infrastructure Protection (CIP) Reliability Standards. Both violations posed a serious risk to the reliability of the BPS.[22] Similarly, in September 2017, NERC filed a full NOP resolving 59 violations, including nine Operations and Planning Reliability Standards and 50 CIP Reliability Standards.[23]

The Regional Entities' effective use of FFTs and CEs – validated through oversight mechanisms such as the annual joint review described below – shows increased consistency in processing and understanding of the risk associated with individual noncompliance across the ERO Enterprise. Further, risk-based enforcement, through the CE and FFT programs, encourages sustainable reliability and security through comprehensive mitigation that addresses root causes

[20] *Id*.

[21] From January 1, 2018, through June 30, 2018, NERC posted 400 CEs out of 456 total posted or filed instances of minimal risk noncompliance. *See supra* n.7.

[22] *North American Electric Reliability Corp.*, NERC Full Notice of Penalty regarding Unidentified Registered Entity, FERC Docket No. NP18-7-000 (FERC Feb. 28, 2018). While filed in FY 2018, much of the work was conducted during FY 2017. The penalty for this full NOP was $2,700,000.

[23] *North American Electric Reliability Corp.*, NERC Full Notice of Penalty regarding Unidentified Registered Entity, FERC Docket No. NP17-31-000 (FERC Sept. 28, 2018). The penalty for this full NOP was $500,000.

with the implementation of internal controls that reduce the likelihood of recurrence of the noncompliance.

III. JOINT NERC AND FERC ANNUAL REVIEW OF THE FFT AND CE PROGRAMS

As part of their oversight of the FFT and CE programs, NERC and FERC staff conducted a joint review of FFTs and CEs posted by NERC between October 2016 and September 2017. The annual joint review began in October 2017 and ended in June 2018. During the review, NERC and FERC staff: (a) evaluated the Regional Entities' current FFT and CE procedures and processes; (b) reviewed a sample of minimal and moderate risk issues processed as FFTs and CEs; (c) assessed successful completion of mitigation for FFTs and CEs requiring the performance of ongoing mitigation activities; (d) evaluated the Regional Entities' assessment of registered entities' internal controls; (e) identified region-specific best practices and areas for improvement; and (f) provided observations to the Regional Entities related to the completeness of the programs. Through this review, NERC and FERC staff determined whether the Regional Entities were following the NERC CMEP and successfully implementing the FFT and CE programs.[24]

On July 25, 2018, FERC staff issued its Notice of Staff Review of Compliance Programs. FERC staff agreed with NERC that the FFT and CE programs are meeting expectations.[25] FERC staff also agreed with the Regional Entities' final risk determinations for 124 of the 126 samples, and noted significant improvement in the clear identification of factors affecting the risk prior to mitigation.[26] Further, FERC staff noted that the identification of root cause has significantly

[24] For a more detailed description of the review, *see infra* Appendices A-B.

[25] *North American Electric Reliability Corp.*, Notice of Staff Review of Compliance Programs, Docket No. RC11-6-007 (FERC July 25, 2018).

[26] *Id.* For the remaining two issues, FERC staff determined the posted information did not sufficiently support the Regional Entity's final determination of risk.

improved over the past four years.[27] In July 2018, NERC Enforcement staff provided individual feedback to the Regional Entities with specific findings and recommendations for each region.

The sampling also indicated that registered entities had adequately mitigated 125 (99.2%) instances of noncompliance, with the remaining CE to be adequately remediated once the ongoing mitigation is completed as scheduled. The sample analysis also indicated a small number of documentation concerns, particularly with regard to the quality of the information contained in the FFT and CE postings.[28] For example, a few of the FFTs or CEs lacked some of the information necessary for posting of noncompliance, such as start or end dates and root causes. However, a subsequent review of the supporting information for these FFTs or CEs identified a majority of the missing information.[29] NERC Enforcement staff continues to work with the Regional Entities to ensure that all information necessary to understand the scope of the noncompliance and the extent of the reliability risk is included in the FFT or CE posting.

The results of the annual joint review show consistent improvement in program implementation. The results also show significant alignment across the ERO Enterprise, particularly in the processing and understanding of the risk associated with individual noncompliance. For a more detailed discussion of the findings from the annual joint FFT and CE review, see Appendices A and B.

[27] *Id*.

[28] *See infra* Appendix B, at 13-16.

[29] *See id*.

IV. ONGOING NERC REVIEWS OF NONCOMPLIANCE AND RELATED PROCESSES

The ERO Enterprise is continuously refining its processes and identifying additional areas for improvement.[30] FFTs and CEs are subject to a 60-day review by NERC and FERC after posting of the issues each month.[31] NERC uses any issues identified in the reviewed samples to provide guidance to the Regional Entities, ensure consistency, and identify future improvements to the programs.

In 2018, the ERO Enterprise also improved its guidance to registered entities. This included revising the Registered Entity Self-Report and Mitigation Plan User Guide to provide additional guidance on the most important information related to noncompliance and mitigation.[32]

[30] *See* North American Electric Reliability Corp., *2017 ERO Enterprise Compliance Monitoring and Enforcement Program Annual Report* (Feb. 7, 2018), https://www.nerc.com/pa/comp/Reports%20DL/2017%20NERC%20Compliance%20Monitoring%20Enforcement%20Program.pdf.

[31] *North American Electric Reliability Corp.*, 150 F.E.R.C. ¶ 61,108 at PP 47-48 (2015).

[32] The updated Registered Entity Self-Report and Mitigation Report User Guide includes examples of description, scope, cause, risk, and mitigation, as well as instructions on what should be included in Self-Reports, Mitigation Plans, and Mitigation Activities. *See* North American Electric Reliability Corp., *Registered Entity Self-Report and Mitigation Plan User Guide*, Appendices A, B, and C (June 2018), https://www.nerc.com/pa/comp/CE/Enforcement%20Actions%20DL/Registered%20Entity%20Self-Report%20and%20Mitigation%20Plan.pdf.

V. CONCLUSION

NERC respectfully requests that the Commission accept this report in compliance with the March 15 Order, June 20 Order, September 18 Order, and November 13 Order.

Respectfully submitted,

/s/ Alexander Kaplen

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Counsel for the North American Electric Reliability Corporation

Dated: November 1, 2018

APPENDIX A. Methodology and Criteria Applied in FFT and CE Sampling

The NERC and FERC staff FY 2017 joint review involved a sample of 26 FFTs and 100 CEs for the period from October 2016 through September 2017. FERC staff performed the sampling of FFTs and CEs, with feedback from NERC on specific instances to be included in the sample. NERC Enforcement staff issued data requests to the Regional Entities on behalf of both organizations.

FERC staff used RATS-STATS[33] to select 15 CIP and 11 non-CIP FFTs from the 75 FFTs posted in fiscal year 2017. FERC staff also selected 43 CIP and 57 non-CIP CEs from the 740 CEs posted during the same period.

Table 1: Sample Size of FFTs for all Regional Entities

FFTs				
	Total Processed	Selected	Percent Representation of Total Processed	Percent Representation of Selected
Total	75	26	% of 75	% of 26
FRCC	4	2	5%	8%
MRO	8	2	11%	8%
NPCC	5	2	7%	8%
RFC	33	11	44%	42%
SERC	3	1	4%	4%
SPP	4	0	5%	NA
TRE	10	5	13%	19%
WECC	8	3	11%	12%

[33] RATS-STATS is a statistical audit tool used by the U.S. Department of Health and Human Services, Office of Inspector General, and Office of Audit Services and developed by the Regional Advanced Techniques Staff (RATS).

Table 2: Sample Size of CEs for all Regional Entities

Compliance Exceptions				
	Total Processed	Selected	Percent Representation of Total Processed	Percent Representation of Selected
Total	740	100	% of 740	% of 100
FRCC	17	3	2%	3%
MRO	52	7	7%	7%
NPCC	31	5	4%	5%
RFC	193	28	26%	28%
SERC	63	10	9%	10%
SPP	95	0	13%	NA
TRE	86	11	12%	11%
WECC	203	36	27%	36%

NERC requested that the Regional Entities provide all FFT- and CE-related documents for the items included in the sample set, including, but not limited to: procedural documents; follow-up or sampling program procedures regarding mitigation completion; source documents; notices of eligibility; documents describing mitigation activities; certifications; affidavits; verification documents, if applicable; and evidence demonstrating the noncompliance was successfully mitigated. NERC examined the selected noncompliance and the documents received using nine criteria described in NERC's FFT/CE Process Review Checklist.[34] The criteria were based on three major categories: (a) the description of the issue was clear and sufficient facts were included; (b) the risk determination was aligned with the facts and circumstances of each particular issue;

[34] NERC's FFT/CE Process Review Checklist is included as **Attachment 1**.

and (c) the issues were timely and appropriately mitigated, with open issues being mitigated within one year.

In addition to the above criteria, NERC Enforcement staff reviewed the documents provided by the Regional Entities to determine whether there were any cases where the Regional Entities omitted known information that would have helped NERC and FERC staff's review of mitigating activities. NERC Enforcement staff also assessed whether the root cause was appropriately identified, leading to effective mitigation. Where feasible, NERC Enforcement staff's review also focused on whether a registered entity's internal processes and controls contributed to the mitigation of the risk during the pendency of the noncompliance.

NERC made informational filings of data requests and Regional Entities' responses for the public record. NERC also filed with FERC the information regarding the Regional Entities' processes and the specific FFTs and CEs on a privileged/non-public basis.

APPENDIX B. Specific Analysis of the Sampled Issues

A. Process documents

NERC found that, generally, each of the Regional Entities' internal documents and procedures regarding the FFT and CE programs follow the NERC Rules of Procedure and CMEP. Each Regional Entity has detailed internal procedures that provide systematic guidance in the processing of noncompliance. These documents assured NERC Enforcement staff that the Regional Entities were properly determining the appropriate processing route for received noncompliance.

The majority of the internal documents and procedures NERC Enforcement staff reviewed showed evidence of periodic reviews and updates. Only a small minority of the procedural documents reviewed did not contain evidence of reviews and updates, or appeared not to have been updated within the last three years. While NERC does not have specific requirements regarding the maintenance of Regional Entities' internal documents and procedures, NERC expects Regional Entities to update procedural documents following significant changes to processes and procedures. Including the effective date and version history in procedural documents helps ensure that procedures are up to date with current requirements.

Additionally, some of the Regional Entities had not updated their procedural documents to include the requirement contained in FERC's November 4, 2015 order[35] that registered entities retain relevant records for 18 months after the date of posting or until verification.[36] Nonetheless, the notifications of FFT or CE treatment from the Regional Entities to the

[35] *North American Electric Reliability Corp.,* 153 F.E.R.C. ¶ 61,130 (2015).

[36] *Id.* at 13.

registered entities did include an 18-month retention requirement. NERC recommends that all Regional Entities include an 18-month retention requirement in their procedural documents.

B. Description of the issue and risk assessment

NERC and FERC staff reviewed the description of the issue associated with each FFT and CE sampled. In all posted FFTs and CEs sampled as part of this review, the Regional Entities adequately identified the risks to the reliability of the BPS. Occasionally, the Regional Entities omitted relevant facts and circumstances from the description and risk assessment. While those facts and circumstances may have helped facilitate a better understanding of the cases, they were not always critical for the risk assessment.

Some samples revealed instances where the Regional Entities either omitted or did not accurately identify the duration or root cause of the noncompliance or the presence or absence of compliance history was not included in the posted FFT or CE. In most of these samples, a subsequent review of the supporting information for these FFTs or CEs led to the identification of the missing information. The Regional Entities provided the majority of the relevant missing information not found in the supporting documents in response to a Request for Information (RFI) issued by NERC Enforcement staff and FERC staff.

NERC Enforcement staff found, through review of the provided documentation, that the Regional Entities adequately and consistently assessed the risk of each noncompliance as either minimal or moderate risk. The majority of the sampled cases also included details of the risk assessments by incorporating specific facts and circumstances at the time of the noncompliance. NERC will continue collaborating with the Regional Entities to ensure the relevant information needed for a complete description and risk assessment is included for all noncompliance.

NERC reviewed the sampled CEs and FFTs to confirm whether the root cause was clearly identified for each noncompliance. The appropriate identification of the root cause is important for effective mitigation and prevention of recurrence of noncompliance. FERC staff and NERC Enforcement staff agreed that the Regional Entities have significantly improved their identifying the root cause of noncompliances in FFTs and CEs over the past four years. NERC Enforcement staff identified a few sampled CEs and FFTs where the root cause was either missing or inaccurately attributed to "human error." Human error is rarely a sole cause of a noncompliance. Rather, human error may instead be a contributing factor to a noncompliance. As a best practice, some Regional Entities clearly differentiated contributing factors from primary causes of noncompliance. NERC Enforcement staff examined more recent CEs and FFTs as part of NERC's 60-day review process and noticed additional improvement in root cause identification from FY 2017 to Q1 and Q2 2018.

C. Evaluation and documentation of mitigation activities

NERC Enforcement staff determined that the Regional Entities were generally requiring detailed and reasonably complete evidence to address the instant noncompliance and abatement of future occurrences. In two cases, Regional Entities only provided registered entities' responses to data requests to show how the registered entities mitigated the noncompliance. Some Regional Entities differentiated between actions to bring an entity back into compliance and actions designed to prevent recurrence. NERC recommends that, as a best practice, Regional Entities delineate between actions to bring an entity back into compliance and actions to prevent recurrence.

There were a few instances, as mentioned above, where the root cause was not robust or was missing from the posted FFT or CE. NERC Enforcement staff, however, determined that

those FFTs and CEs included mitigation that was generally adequate to prevent recurrence. This provides reassurance that, although a few listed FFTs and CEs did not have adequate root cause information, the registered entity and Regional Entity understood where the problem existed. Accurately identifying the root cause of noncompliance is important, as it directly relates to the effectiveness of mitigation actions. NERC Enforcement staff, therefore, recommends the Regional Entities continue to focus training for their registered entities on robust cause statements, and consider describing cause, risk, and mitigation in a holistic manner to ensure each element is present.

ATTACHMENT 1. Process Review Checklist

2017 - 2018 FFT and Compliance Exception Process Review Checklist

Any procedural documents or training documents that are used for the FFT and Compliance Exception process.	
Title, revision	*Summary of the document*
Title, revision	*Summary of the document*
Title, revision	*Summary of the document*
Title, revision	*Summary of the document*

Follow-up or Sampling Program, e.g., audit or spot-check documents. Follow-up on closed issues and issues posted originally as open. Does the RE have a sampling process for random checking of completion or a spot check or audit process, to the extent it does not verify completion of mitigating activities?	
Title, revision	*Summary of the document*
Title, revision	*Summary of the document*
Title, revision	*Summary of the document*
Title, revision	*Summary of the document*

Results

Summarize your findings under the following categories:

1. Were the underlying facts and circumstances included? Was the root cause considered? Were there any cases where the REs “omitted known information that would have facilitated NERC and FERC in review of the mitigating activities?” NERC Enforcement will assess whether the root cause was appropriately identified leading to effective mitigation.
2. Did the risk assessments include the risk to reliability, including mitigating factors during pendency of the issue? Was the risk determined in a consistent manner? For minimal risk issues, was CE/FFT treatment appropriate? NERC Enforcement will assess, as feasible, whether internal controls contributed to the mitigation of the risk during the pendency of the noncompliance. Ensure that the risk was not considered a minimal risk simply because of no adverse impact ("no harm no foul").
3. Were the issues mitigated successfully? For ongoing mitigation, was it successfully completed and certified? If the CE/FFT is associated with a formal Mitigation Plan, NERC Enforcement will determine whether a formal Mitigation Plan was necessary or if the RE requested a formal Mitigation Plan and explained the circumstances that required it.

	Questions	Issue Tracking ID
	Type - FFT/CE	
	Standard	
	Requirement	
1	The description of the issue was adequate and includes the following: a) Description of the issue, underlying facts and circumstances. For CEs, indicate if it was self-logged. b) Discovery date and method of the issue. c) Duration of the violation - start and end dates of the issue. d) Explanation and proper identification of root cause. e) Compared to the evidence, the description of the issue that was posted is accurate and reasonably complete.	
2	Risk Statement adequately addresses the issue. a) The issue posed a minimal (for CEs and FFTs) or moderate risk (for FFTs) to the BPS and does not warrant a monetary penalty. For moderate risk issues, the statement explains why it is appropriate for FFT treatment. b) Risk statement based on actual risk, at the time of the issue. c) Risk statement is based on the root cause, not a generic statement related to any noncompliance of the specific Reliability Standard and Requirement. d) Risk statement addresses mitigating factors that reduced the actual risk and compensating factors as relevant to the entity and circumstances. (Does not include a blanket heightened risk statement related solely to the Standard (R) at issue.) e) Indication of no actual harm (does not require "No harm is known to have occurred" if the risk assessment otherwise indicates that no harm occurred) f) If issue is ongoing, a description of all compensating measures in place during the period of noncompliance which reduce the risk to reliability while mitigation is ongoing. g) Compared to the evidence, the posted description of the risk assessment is accurate and reasonably complete.	
3	The mitigating activities address both the current issue and abatement of future occurrences. a) Includes specific mitigation activities or steps to be taken. b) Addresses root cause of the issue and actions to prevent recurrence. c) Compared to the evidence, the posted description of the mitigation is accurate and reasonably complete. d) Based on the evidence and activities, does the issue appear to be appropriately remediated (mitigated)? e) While not required, state whether completion of mitigating activities verified for completed activities. Or If posted as an ongoing issue, the mitigating activities were/will be completed within one year and indicate: a) the expected completion date. b) the justification for the length of time required.	

4	For FFTs, an affidavit of completion signed by an officer with knowledge of the remediation was provided. For CEs, other certification document/written notice to show that mitigated was completed.	
5	For ongoing mitigation, RE tracked and followed up to ensure that mitigation activities were successfully completed and certified.	
6	The RE considered the compliance history when evaluating this issue. The RE considered the compliance history and determined there were no relevant instances of noncompliance OR includes applicable compliance history and how it is different from the instant issue or otherwise does not warrant a penalty or aggravation. a) Have there been any re-occurrences since the mitigation activities were completed? For FFT review, Compliance Exceptions are not considered a part of the compliance history unless the most recent one is an event or they continue to violate the same Standard/Req.	
7	The registered entity was notified of FFT/CE treatment at least 10 days before date of posting. For issues with completed mitigation at the time of posting, a notice that shows that after 60 days of posting the issue is considered to be closed if FERC/NERC have no issues. For issues with ongoing mitigation at the time of posting, the issue is closed after mitigation completion or after 60 days of posting, whichever is later. For CEs - Did any of the notification letters include a statement about the 18-month record retention period per FERC's November 15 order?	
8	Was there any information in the provided evidence that should have been included in the final posting? For example, information related to the description of the issue or factors affecting the risk assessment.	
9	Overall Satisfactory? If not, state why or refer to checklist numbers that are unsatisfactory.	

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 1st day of November 2018.

/s/ Alexander Kaplen

Alexander Kaplen
Associate Counsel for the North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Standards for Business Practices and Communication Protocols for Public Utilities	**)** **)** **)**	**Docket No. RM05-5-026**

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN SUPPORT OF NOTICE OF PROPOSED RULEMAKING

The North American Electric Reliability Corporation ("NERC") hereby provides comments in support of the Federal Energy Regulatory Commission ("Commission") Notice of Proposed Rulemaking ("NOPR") to revise the Commission's regulations at 18 CFR § 38.1(b) to remove the incorporation by reference of Wholesale Electric Quadrant WEQ-006 Time Error Correction Business Practice Standards ("WEQ-006") as adopted by the North American Energy Standards Board ("NAESB") in its WEQ Version 003.0 Businesses Practice Standards.[1]

Notices and communications with respect to these comments may be addressed to:

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I. COMMENTS

NERC supports the NOPR and NAESB's reservation, or retirement, of WEQ-006. NAESB reserved WEQ-006 in coordination with NERC's retirement of Reliability Standard

[1] *Standards for Business Practices and Communication Protocols for Public Utilities*, 165 FERC ¶ 61,007 (2018) ("NOPR") (proposing to also incorporate by reference NAESB Standard WEQ-000 (Version 0003.2), eliminating the definitions of "Time Error" and "Time Error Correction" and making other minor edits.).

BAL-004-0 (*Time Error Correction*), as approved by the Commission in 2017.[2] As referenced in the NOPR[3] and detailed in NERC's petition for retirement of Reliability Standard BAL-004-0, coordinated retirement of WEQ-006 and Reliability Standard BAL-004-0 ensures clarity and avoids inadvertent, uncoordinated, manual time error correction.[4]

On March 27, 2017, NAESB filed a status report with the Commission regarding the reservation of WEQ-006.[5] Consistent with NERC's filed and Commission approved Implementation Plan, NERC then retired Reliability Standard BAL-004-0 effective April 1, 2017. Removing the reference to WEQ-006 in 18 CFR § 38.1(b)) will support reliability by ensuring clarity and avoiding uncoordinated manual time error correction.

II. CONCLUSION

NERC respectfully requests that the Commission accept these comments in support of the Notice of Proposed Rulemaking.

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2 *North American Electric Reliability Corporation*, Docket No. RD17-1-000 (Letter Order Jan. 18, 2017).

3 *See*, NOPR, at P 7.

4 *Petition of the North American Electric Reliability Corporation for Retirement of Reliability Standard BAL-004-0*, Docket No. RD17-1-000 (filed Nov. 10, 2016).

5 *Status Report of the North American Energy Standards Board on the reservation of WEQ-006 Manual Time Error Correction Business Practice Standards under RM05-5, et al.*, Docket Nos. RD17-1-000 and RM05-5-000 (filed Mar. 27, 2017).

Respectfully submitted,

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Counsel for the North American Electric Reliability Corporation

Date: October 24, 2018

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service lists compiled by the Secretary in Docket No. RM05-5-026.

Dated at Washington, DC this 24th day of October 2018.

/s/ Courtney M. Baughan

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

October 12, 2018

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

RE: Revision to Implementation Plans for Reliability Standards MOD-026-1 and MOD-027-1; Docket No. RM13-16-000

Dear Secretary Bose:

The North American Electric Reliability Corporation ("NERC") submits for approval the attached revision to the Implementation Plans for Reliability Standards MOD-026-1 (Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions) and MOD-027-1 (Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions), which were approved by the Federal Energy Regulatory Commission ("Commission") in Order No. 796.[1] It has come to NERC's attention that the Implementations Plans for both MOD-026 and MOD-027 erroneously reference "verification date" instead of "transmittal date" to set the periodicity for reverification under each standard.

Attachment 1 of Reliability Standards MOD-026-1 and MOD-027-1 use "transmittal date" to set the periodicity for verifications under each standard. The proposed revision to the Implementation Plans is to ensure that the language in the Implementation Plans is consistent with the language in the Reliability Standards. NERC's standard drafting team for Reliability Standards MOD-026-1 and MOD-027-1 intended to use the term "transmittal date" in the Implementation Plans to allow entities to use a single date for measuring periodicity rather than multiple dates for cases when verifications under the two standards are performed days, weeks, or months from the other for an applicable unit. As such, the proposed revision to the Implementation Plans replaces "verification date" with "transmittal date", consistent with the language in the standards. Clean and redline versions of the revised MOD-026-1 and MOD-027-1 Implementation Plans are provided as **Exhibits A-B** hereto.

[1] Order No. 796, *Generator Verification Reliability Standards*, 79 Fed. Reg. 17,011 (2014) (to be codified at 18 C.F.R. pt. 40).

For the reasons set forth above, NERC respectfully requests that the Commission approve the proposed errata to the MOD-026-1 and MOD-027-1 Implementation Plans.

Respectfully submitted,

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cc: Official service list in Docket No. RM13-16-000

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 12th day of October, 2018.

/s/ Courtney Baughan

Courtney Baughan
Senior Legal Assistant for the North American Electric Reliability Corporation

Exhibit A

MOD-026-1 Implementation Plan

Exhibit A

MOD-026-1 Implementation Plan - Clean Version

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

Approvals Required

MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Planner

For the purpose of this standard, the following Facilities are considered, "applicable units."

Units or plants that meet the following:

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant consisting of multiple units that are directly connected to the Bulk Electric System at a common bus with total generation greater than 100 MVA (gross aggregate rating).

Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

- Each generating plant consisting of multiple units that are directly connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant / Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

For all Interconnections:

- Any technically justified[1] unit that meets NERC registry criteria and is requested by the Transmission Planner.

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 By the first day of the first calendar quarter following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, four years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, six years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure 100 percent of its applicable unit gross MVA are compliant with Requirement R2 By the first day of the first calendar quarter, 10 years

[1] Technical justification is achieved by demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 by the first day of the first calendar quarter following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection is compliant with Requirement R2 by the first day of the first calendar quarter, four years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection is compliant with Requirement R2 By the first day of the first calendar quarter, six years following Board of Trustees adoption.
- Each Generator Owner shall ensure 100 percent of its applicable unit gross MVA is compliant with Requirement R2 By the first day of the first calendar quarter, 10 years following Board of Trustees adoption.

Consideration for Early Compliance

Existing excitation control system and plant volt/var control model verification is sufficient for demonstrating compliance for a 10 year period from the actual transmittal date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification, or
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Justification

This phased implementation supports the 10 year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules.

When a Generator Owner has verified its Excitation Control System and Plant Volt/Var Control model(s) in compliance with its regional entity requirements 10 years or less prior to the approval date of this Standard, these verifications are deemed sufficient for demonstrating compliance with this Standard for a ten year period from the date of the aforementioned transmittal.

Retirements

None

Exhibit A

MOD-026-1 Implementation Plan - Redlined Version

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

Approvals Required

MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Planner

For the purpose of this standard, the following Facilities are considered, "applicable units."

Units or plants that meet the following:

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant consisting of multiple units that are directly connected to the Bulk Electric System at a common bus with total generation greater than 100 MVA (gross aggregate rating).

Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

- Each generating plant consisting of multiple units that are directly connected to the Bulk Electric System at a common bus with total generation greater than -75 MVA (gross aggregate rating).

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant / Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than -75 MVA (gross aggregate rating).

For all Interconnections:

- Any technically justified[1] unit that meets NERC registry criteria and is requested by the Transmission Planner.

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 By the first day of the first calendar quarter following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, four years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, six years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure 100 percent of its applicable unit gross MVA are compliant with Requirement R2 By the first day of the first calendar quarter, 10 years

[1] Technical justification is achieved by demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 by the first day of the first calendar quarter following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection is compliant with Requirement R2 by the first day of the first calendar quarter, four years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection is compliant with Requirement R2 By the first day of the first calendar quarter, six years following Board of Trustees adoption.
- Each Generator Owner shall ensure 100 percent of its applicable unit gross MVA is compliant with Requirement R2 By the first day of the first calendar quarter, 10 years following Board of Trustees adoption.

Consideration for Early Compliance

Existing excitation control system and plant volt/var control model verification is sufficient for demonstrating compliance for a 10 year period from the actual ~~verification~~ transmittal date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification, or
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Justification

This phased implementation supports the 10 year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules.

When a Generator Owner has verified its Excitation Control System and Plant Volt/Var Control model(s) in compliance with its regional entity requirements 10 years or less prior to the approval date of this Standard, these verifications are deemed sufficient for demonstrating compliance with this Standard for a ten year period from the date of the aforementioned ~~verification~~transmittal.

Retirements

None

Exhibit B

MOD-027-1 Implementation Plan

Exhibit B

MOD-027-1 Implementation Plan - Clean Version

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Approvals Required

MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Planner

For the purpose of this standard, the following Facilities are considered, "applicable units." Units or plants that meet the following:

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant or generating Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 100 MVA (gross aggregate rating).

Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

- Each generating plant or generating Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant or generating Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, four years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, six years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
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In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter following Board of Trustees adoption.

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- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, six years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 100 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, 10 years following Board of Trustees adoption.

Justification

This phased implementation supports the ten year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules, and it also provides ample time for Generator Owners to either purchase new recording equipment as required or to make necessary modifications to existing recording equipment (frequency triggers, length of recordings for frequency excursions, additional event storage capacity, etc).

Consideration for Early Compliance

Existing turbine/governor and load control or active power/frequency control model verification is sufficient for demonstrating compliance for a ten year period from the actual transmittal date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification.
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Retirements

None

Exhibit B

MOD-027-1 Implementation Plan - Redlined Version

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Approvals Required

MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Planner

For the purpose of this standard, the following Facilities are considered, "applicable units." Units or plants that meet the following:

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

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- Each generating plant or generating Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant or generating Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
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In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter following Board of Trustees adoption.

- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, four years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, six years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 100 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, 10 years following Board of Trustees adoption.

Justification

This phased implementation supports the ten year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules, and it also provides ample time for Generator Owners to either purchase new recording equipment as required or to make necessary modifications to existing recording equipment (frequency triggers, length of recordings for frequency excursions, additional event storage capacity, etc).

Consideration for Early Compliance

Existing turbine/governor and load control or active power/frequency control model verification is sufficient for demonstrating compliance for a ten year period from the actual ~~verification~~ transmittal date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification.
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Retirements

None

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED REVISIONS TO APPENDIX 4E TO THE RULES OF PROCEDURE

Edwin G. Kichline
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October 16, 2018

TABLE OF CONTENTS

I. NOTICES AND COMMUNICATIONS 3

II. BACKGROUND 3

A. Regulatory Framework 3

B. Appendix 4E Section CCCPP-004 of the NERC ROP 3

C. Development of Proposed Revisions 4

III. SUMMARY OF PROPOSED REVISIONS 4

1. CCCPP-004: CCC Hearing Procedures 4

2. CCCPP-006: CCC Mediation Procedures 5

IV. CONCLUSION 5

Exhibit A Proposed NERC Rules of Procedure Appendix 4E
CCCPP-004-2 Hearing Procedures – Clean and Redline Versions

Exhibit B Proposed NERC Rules of Procedure Appendix 4E
CCCPP-006-2 Mediation Procedures – Clean and Redline Versions

Exhibit C Comments on Proposed Revisions

Exhibit D Consideration of Comments

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED REVISIONS TO APPENDIX 4E TO THE RULES OF PROCEDURE

Pursuant to Section 215(f) of the Federal Power Act ("FPA")[1] Section 39.10 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] the North American Electric Reliability Corporation ("NERC") hereby requests Commission approval of proposed revisions to Appendix 4E (Compliance and Certification Committee ("CCC") Hearing Procedures, and Mediation Procedures) of its Rules of Procedure ("ROP"). The purpose of the proposed revisions, provided in Exhibit A hereto, is to align the rules and procedural steps of the Hearing Procedures used in the Compliance Monitoring and Enforcement Program ("CMEP") as per the CCC Charter. For the reasons set forth in this petition, NERC requests that the Commission approve the proposed revisions as just, reasonable, not unduly discriminatory, or preferential, and in the public interest. NERC also requests that the proposed revisions become effective upon Commission approval.

[1] 16 U.S.C. §824o(f) (2018).
[2] 18 C.F.R. § 39.10 (2018).

I. NOTICES AND COMMUNICATIONS

Notices and communications regarding this filing may be addressed to the following:

Edwin G. Kichline
Senior Counsel and Director of Enforcement Oversight
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
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II. BACKGROUND

A. Regulatory Framework

Section 215(f) of the FPA provides the regulatory framework for revisions to the NERC ROP, stating that "[t]he Electric Reliability Organization ["ERO"] shall file with the Commission for approval any proposed rule or proposed rule change, accompanied by an explanation of its basis and purpose," and that the proposed rule or rule change "shall take effect upon a finding by the Commission, after notice and opportunity for comment, that the change is just, reasonable, and not unduly discriminatory or preferential, is in the public interest, and satisfies the requirements of subsection (c) [of § 215]."[3] The Commission's regulations at 18 C.F.R. § 39.10 reiterate these requirements and additionally require that the filing include "a description of the proceedings conducted by the ERO… to develop the proposal." The NERC ROP are ERO rules as defined in Section 39.1 of the Commission's regulations.[4]

B. Appendix 4E Section CCCPP-004 of the NERC ROP

Appendix 4E Section CCCPP-004 requires that the Hearing Procedure is mandated and approved by jurisdictional authorities for use by NERC and the Regional Entities in the

[3] 16 U.S.C. § 824o(f).
[4] 18 C.F.R. § 39.1.

Compliance Monitoring and Enforcement Program contained in Section 403 of the ROP. The CCC serves as the hearing body for any contest regarding Penalties for violation of NERC Reliability Standards where NERC itself acts as the Compliance Enforcement Authority. The CCC Charter requires that its Hearing Procedures follow the CMEP Hearing Process unless specifically identified otherwise. For the reasons discussed in Section III of this Petition, NERC proposes revisions to Appendix 4E modifying the Hearing Procedures.

C. Development of Proposed Revisions

NERC publicly posted its proposed revisions on April 13, 2018 for 45-day public comment period. NERC received four sets of comments from industry stakeholders in response to the posting. The comments are provided in Exhibit C. Exhibit D provide NERC's consideration of those comments. The NERC Board of Trustees approved the proposed revisions on August 16, 2018.

III. SUMMARY OF PROPOSED REVISIONS

A detailed discussion of the proposed revisions are as follows:

1. CCCPP-004: CCC Hearing Procedures

NERC proposes changes to Section CCCPP-004 of Appendix 4E to provide consistency of terminology with the Regional Entity ("RE") Hearing Process described in the ROP. The proposed revisions include replacing the term "segment" with "sector" and "NERC Director of Compliance" with "NERC Director of Enforcement." The proposed revisions also include eliminating all common definitions that NERC consolidated in Appendix 2. For clarity and ease of use, definitions unique to the CCC Hearing Procedures remain in section 1.1.5.

Additional proposed revisions to CCCPP-004 focus on structural alignment with the RE Hearing Process described in the ROP. This includes a thorough update to match NERC's most recent report template and the addition of a preface, which introduces the ERO Enterprise and

describes its vision. This also includes section 1.2.12, which allows interventions, in alignment with the Hearing Process and Section 1.4.3, which describes the CCC Hearing Panel, in alignment with the CCC Charter. NERC updated Sections 1.3, 1.5, 1.6, 1.7 and 1.9 and added Sections 1.3.2 and 1.3.3 to align with the corresponding ROP Sections.

NERC is proposing revisions to clarify ambiguities within the Hearing Procedures. The proposed revisions clarify a number of issues including Hearing Panel submissions to the Clerk, filings with the Hearing Panel, representations deemed to be made before them, Hearing Panel termination and composition, and requirements related to Settlements. Other clarifications included ex parte communication exceptions, added in 1.4.7(b), ethical standards, added in 1.4.8(d), Settlement requirements, added in 1.8, and the certification of questions to the NERC Board of Trustees Compliance Committee (BOTCC), added in 1.5.12.

2. CCCPP-006: CCC Mediation Procedures

Proposed revisions to CCCPP-006 are not substantive, but instead update the Mediation Procedures to match NERC's most recent template and formatting changes. The proposed revisions also include a preface, which introduces the ERO Enterprise and describes its vision. The proposed revisions also clarify that parties may discuss interests and concerns with mediators any time once the mediation process begins.

IV. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve the proposed revisions to Appendix 4E of the NERC ROP included in **Exhibits A-B**. In addition, NERC requests that the proposed revisions become effective as specified herein.

Respectfully submitted,

/s/ Edwin G. Kichline

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Counsel for the North American Electric Reliability Corporation

Date: October 16, 2018

Exhibit A

Proposed NERC Rules of Procedure Appendix 4E

CCCPP-004-2 Hearing Procedures – Clean and Redline Versions

CCCPP-004-2 Hearing Procedures – Clean

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Compliance and Certification Committee Hearing Procedures

CCCPP-004-2

Effective: [proposed date], Version 2.0

RELIABILITY | ACCOUNTABILITY






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Table of Contents

Preface v

Hearing Procedures 1

1.1 Applicability, Definitions and Interpretation 1

1.1.1 Procedure Governed 1

1.1.2 Deviation 1

1.1.3 Standards for Discretion 1

1.1.4 Interpretation 2

1.1.5 Definitions 2

1.2 General Provisions including Filing, Service, Transcription and Participation 3

1.2.1 Contents of Filings 3

1.2.2 Form of Filings 3

1.2.3 Submission of Documents 4

1.2.4 Service 4

1.2.5 Computation of Time 5

1.2.6 Extensions of Time 5

1.2.7 Amendments 5

1.2.8 Transcripts 5

1.2.9 Rulings, Notices, Orders and Other Issuances 6

1.2.10 Location of Hearings and Conferences 6

1.2.11 Participant Participation 6

1.2.12 Interventions 6

1.2.13 Proceedings Closed to the Public 7

1.2.14 Docketing System 7

1.2.15 Representations Deemed to be made in All Pleadings 8

1.2.16 Hold Harmless 8

1.3 Initiation of the Hearing Process 9

1.3.1 Registered Entity's Option to Request a Hearing 9

1.3.2 Staff's Response to Request for Hearing 10

1.3.3 Notice of Hearing 10

1.3.4 Shortened Hearing Procedure 10

1.4 General Hearing Procedure 13

1.4.1 [Intentionally Left Blank] 13

1.4.2 Hearing Officer 13

1.4.3 Hearing Panel 14
1.4.4 Interlocutory Review 14
1.4.5 Disqualification 15
1.4.6 Technical Advisor 16
1.4.7 No Ex Parte Communications 16
1.4.8 Appearances 17
1.4.9 Failure to Appear or Exercise Diligence 17
1.4.10 Consolidation of Proceedings 18
1.5 Prehearing Procedure 0
1.5.1 [Intentionally Left Blank] 0
1.5.2 Prehearing Conference 0
1.5.3 Summary Disposition 0
1.5.4 Status Hearings 1
1.5.5 Motions and Responses 1
1.5.6 Experts 1
1.5.7 Inspection and Copying of Documents in Possession of Staff 2
1.5.8 Other Discovery Procedures 4
1.5.9 Pre-Evidentiary Hearing Submission of Testimony and Evidence 5
1.5.10 Protective Orders 6
1.5.11 Pre-Evidentiary Hearing Memorandum 7
1.5.12 Certification of Questions to the NERC Board of Trustees Compliance Committee 7
1.6 Procedure at Evidentiary Hearing 9
1.6.1 Purpose of Evidentiary Hearing 9
1.6.2 Order of Receiving Evidence 9
1.6.3 Opening and Closing Statements 9
1.6.4 Right of Participant to Present Evidence 9
1.6.5 Exhibits 9
1.6.6 Witness Attendance at Testimonial Hearing 9
1.6.7 Admission of Evidence 10
1.6.8 Evidence that is Part of a Book, Paper or Document 10
1.6.9 Stipulations 10
1.6.10 Official Notice 11
1.6.11 Admissibility of Evidence 11
1.6.12 Offer of Proof 11
1.6.13 Reservation of Evidentiary Ruling 11

1.6.14 Cross-Examination 12
1.6.15 Redirect Examination 12
1.6.16 Examination of Adverse Participant 12
1.6.17 Close of the Evidentiary Record 12
1.7 Post Evidentiary Hearing Procedure 13
1.7.1 Briefs 13
1.7.2 Other Pleadings 13
1.7.3 Draft Initial Opinions 13
1.7.4 Hearing Officer's Initial Opinion 13
1.7.5 Exceptions 13
1.7.6 Oral Argument 14
1.7.7 Additional Hearings 14
1.7.8 Hearing Panel Final Order 15
1.7.9 The Record 15
1.7.10 Appeal 16
1.8 Settlement 17
1.9 Remedial Action Directives 18
1.9.1 Initiation of Remedial Action Directive Hearing 18
1.9.2 Remedial Action Directive Hearing Procedure 18

NERC Compliance and Certification Committee		**CCCPP-004-2**
Title: Hearing Procedures		
Version: 2.0	**Revision Date: March 21, 2018**	**Effective Date: [proposed date]**

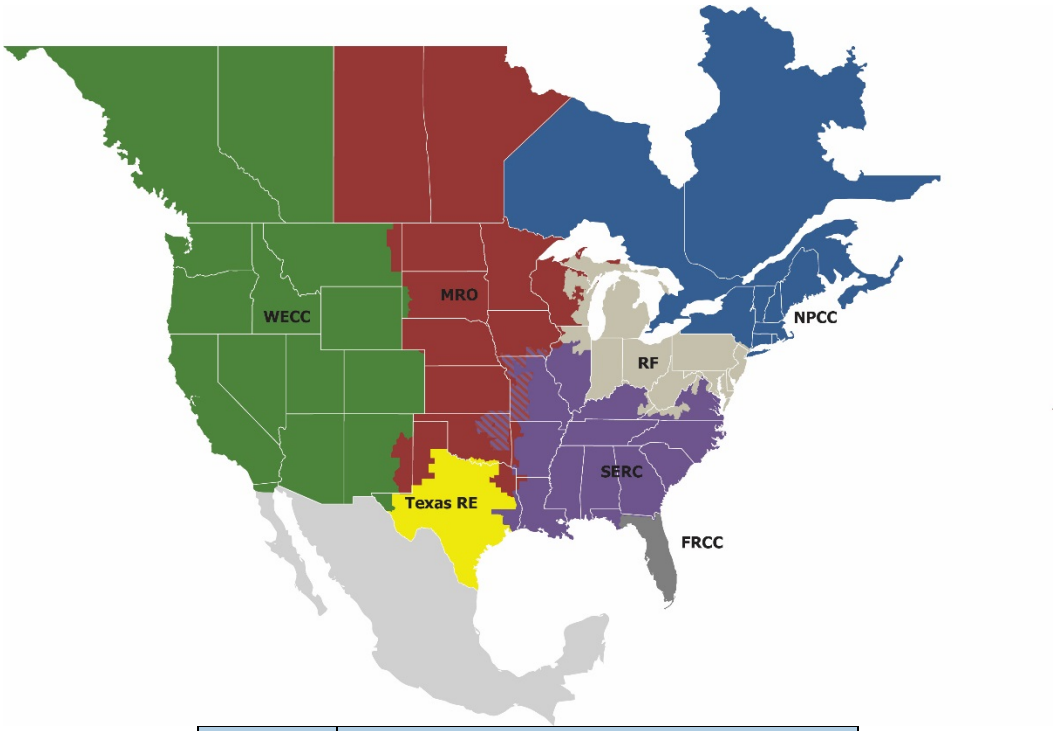
Revision History

Date	Version Number	Comments
03/03/09	1.0	Approved by CCC
05/06/09	1.0	Approved by the Board of Trustees
03/21/18	2.0	Approved by CCC
08/16/18	2.0	Approved by the Board of Trustees

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 Regional Entity 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

Hearing Procedures

1.1 Applicability, Definitions and Interpretation

1.1.1 Procedure Governed

The provisions set forth in this Attachment ("Hearing Procedures") shall apply to and govern practice and procedure before the Compliance and Certification Committee (CCC) in hearings in the United States, provided, that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions, as described in the NERC ROP Section 404. Specifically, as directed by the NERC Board of Trustees, the CCC serves as the hearing body for any contest regarding findings of penalties or sanctions for violation(s) of Reliability Standard(s) where NERC is acting as the Compliance Enforcement Authority (CEA) and is directly monitoring the Registered Entity for compliance with those Reliability Standards (Registered Entity by agreement with a Regional Entity or absent a delegation agreement; the Regional Entity itself where approved Reliability Standards are applicable to the Regional Entity).

The CCC shall determine: (i) whether such Registered Entities have violated Reliability Standards, and if so, the appropriate Mitigation Plan or Mitigating Activities as well as any Remedial Action Directives, Penalties and/or sanctions in accordance with the NERC *Sanction Guidelines* and other applicable Penalty guidelines approved by FERC pursuant to 18 C.F.R. § 39.7(g)(2); or (ii) a challenge by a Regional Entity regarding a Regional Entity Compliance Audit finding by NERC.

Any hearing conducted pursuant to these Hearing Procedures shall be conducted before a Hearing Officer and a Hearing Panel established by the CCC. Where the Hearing Panel is comprised, in whole or in part, of industry stakeholders, the composition of the Hearing Panel, after any recusals or disqualifications, shall be such that no two industry sectors may control, and no single industry sector may veto, any decision by the Hearing Panel on any matter brought before it for decision. Where the Hearing Panel is comprised solely of independent members and an independent Hearing Officer, decisions shall require a majority vote.

The standard of proof in any proceeding under these Hearing Procedures shall be by a preponderance of the evidence. The burden of persuasion on the merits of the proceedings shall rest upon the Staff alleging noncompliance with a Reliability Standard, proposing a Penalty, opposing a Registered Entity's Mitigation Plan or Mitigating Activities, or requiring compliance with a Remedial Action Directive.

If a final order has been entered by the Hearing Panel, or the Hearing Panel has issued a ruling determining that there are no issues to be decided regarding the Alleged Violation, proposed Penalty amount, proposed Mitigation Plan or Mitigating Activities, or proposed Remedial Action Directive, or the Registered Entity and the CEA have entered into a settlement agreement resolving the matters that are the subject of the hearing, the hearing shall be terminated by the Hearing Panel and no further proceedings shall be conducted before the Hearing Panel.

1.1.2 Deviation

To the extent permitted by law, any provision in these Hearing Procedures may be waived, suspended, or modified by the Hearing Officer or the Hearing Panel, for good cause shown, either upon the Hearing Officer's or the Hearing Panel's own motion or upon the motion of any Participant.

1.1.3 Standards for Discretion

The CCC's discretion under these Hearing Procedures shall be exercised to accomplish the following goals:

(a) Integrity of the Fact-Finding Process - The principal goal of the hearing process is to assemble a complete factual record to serve as a basis for a correct and legally sustainable ruling, decision, or order.

(b) Fairness - Persons appearing in CCC proceedings should be treated fairly. To this end, Participants should be given fair notice and opportunity to present explanations, factual information, documentation, and legal argument. Action shall be taken as necessary to eliminate any disadvantage or prejudice to a Participant that would otherwise result from another Participant's failure to act diligently and in good faith.

(c) Independence - The hearing process should be tailored to protect against undue influence from any Person, Participant, or interest group.

(d) Balanced Decision-Making - Decisions should be based solely on the facts and arguments of record in a proceeding and by individuals who satisfy NERC's conflict of interest policy.

(e) Impartiality - Persons appearing before the Hearing Panel should not be subject to discriminatory or preferential treatment. Registered Entities should be treated consistently unless a reasonable basis is shown in any particular proceeding to depart from prior rulings, decisions, or orders.

(f) Expedition - Proceedings shall be brought to a conclusion as swiftly as is possible in keeping with the other goals of the hearing process.

1.1.4 Interpretation

(a) These Hearing Procedures shall be interpreted in such a manner as will aid in effectuating the Standards for Discretion set forth in Section 1.1.3, and so as to require that all practices in connection with the hearings shall be just and reasonable.

(b) Unless the context otherwise requires, the singular of a term used herein shall include the plural and the plural of a term shall include the singular.

(c) To the extent that the text of a rule is inconsistent with its caption, the text of the rule shall control.

1.1.5 Definitions

Unless otherwise defined below, capitalized terms used in these Hearing Procedures shall have the meanings set forth in Appendix 2 of the NERC Rules of Procedure.

"Clerk" shall mean an individual assigned by the CCC to perform administrative tasks relating to the conduct of hearings as described in these Hearing Procedures.

"Compliance Enforcement Authority" or (CEA) means NERC in its respective role of monitoring and enforcing compliance with the NERC Reliability Standards.

"Days", as used within these Hearing Procedures, means calendar days.

"Director of Enforcement" means the Director of Enforcement of the CEA, as applicable, or other individual designated by the CEA, who is responsible for the management and supervision of Enforcement Staff, or his or her designee.

"Hearing Officer" means, solely for hearings conducted pursuant to Appendix 4E, (A) a CCC member or (B) an individual employed or contracted by NERC, as designated and approved by the CCC to preside over hearings conducted pursuant to the Hearing Procedures in Appendix E; the Hearing Officer shall not be a member of the Hearing Panel.

"Hearing Panel" means the five person hearing body established as set forth in the CCC Charter on a case by case basis and that is responsible for adjudicating a matter as set forth in Section 1.1.1 above.

"Participant" means a Respondent and any other Person who is allowed or required by the Hearing Panel or by FERC to participate as an intervenor in a proceeding conducted pursuant to these Hearing Procedures, and as used in these Hearing Procedures shall include the members of the Staff of the CEA that participate in a proceeding.

"Staff" means individuals employed or contracted by NERC who have the authority to make initial determinations of compliance or violation with Reliability Standards by Registered Entities and associated Penalties, Mitigation Plans or Mitigating Activities.

1.2 General Provisions including Filing, Service, Transcription and Participation

1.2.1 Contents of Filings

All filings made with the Hearing Panel must contain:

(a) A caption that sets forth the title of the proceeding and the designated docket number or, if the filing initiates a proceeding, a space for the docket number;

(b) A heading that describes the filing and the Participant on whose behalf the filing is made;

(c) The full name, address, telephone number and email address of the Participant or the representative of the Participant making the filing;

(d) A plain and concise statement of any facts upon which the filing is based, which facts shall be supported by citations to the record of the hearing, if available, or other evidence; and

(e) The specific relief sought, which may be in the alternative, and the authority that provides for or otherwise allows the relief sought.

1.2.2 Form of Filings

(a) All filings shall be typewritten, printed, reproduced, or prepared using a computer or other word or data processing equipment on white paper 8½ inches by 11 inches with inside text margins of not less than one inch. Page numbers shall be centered and have a bottom margin of not less than ½ inch. Line numbers, if any, shall have a left-hand margin of not less than ½ inch. The impression shall be on one side of the paper only and shall be double spaced; footnotes may be single spaced and quotations may be single spaced and indented.

(b) All pleadings shall be composed in either Arial or Times New Roman font, black type on white background. The text of pleadings or documents shall be at least 12-point. Footnotes shall be at least 10-point. Other material not in the body of the text, such as schedules, attachments and exhibits, shall be at least 8-point.

(c) Reproductions may be by any process provided that all copies are clear and permanently legible.

(d) Testimony prepared for the purpose of being entered into evidence shall include line numbers on the left-hand side of each page of text. Line numbers shall be continuous.

(e) Filings may include schedules, attachments, or exhibits of a numerical or documentary nature which shall, whenever practical, conform to these requirements; however, any log, graph, map, drawing, chart, or other such document will be accepted on paper larger than prescribed in subparagraph (a) if it cannot be provided legibly on letter size paper.

1.2.3 Submission of Documents

(a) **Where to File:** Filings shall be made with the NERC Director of Enforcement located at **NERC's Washington, DC** office. The office will be open during NERC's regular business hours each day except Saturday, Sunday, legal holidays and any other day declared by NERC.

(b) **When to File:** Filings shall be made within the time limits set forth in these Hearing Procedures or as otherwise directed by the Hearing Officer or the Hearing Panel. Filings will be considered made when they are date stamped when received by the NERC Director of Enforcement. To be timely, filings must be received no later than 5:00 p.m., local time on the date specified.

(c) **How to File:** Filings may be made by personal delivery, mailing documents that are properly addressed with first class postage prepaid, or depositing properly addressed documents with a private express courier service with charges prepaid or payment arrangements made. Alternatively, filing by electronic means will be acceptable upon implementation of a suitable and secure system.

(d) **Number of Copies to File:** One original and five exact copies of any document shall be filed. The Clerk will provide each member of the Hearing Panel with a copy of each filing.

(e) **Signature:** The original of every filing shall be signed by the Participant on whose behalf the filing is made, either by an attorney of the Participant or, by the individual if the Participant is an individual, by an officer of the Participant if the Participant is not an individual, or if the Participant is Staff, by a designee authorized to act on behalf of Staff. The signature on a filing constitutes a certificate that the signer has read the filing and knows its contents, and that the contents are true to the best of the signer's knowledge and belief.

(f) **Verification:** The facts alleged in a filing need not be verified unless required by these Hearing Procedures, the Hearing Officer, or the Hearing Panel. If verification is required, it must be under oath by a person having knowledge of the matters set forth in the filing. If any verification is made by an individual other than the signer, a statement must be included in or attached to the verification explaining why a person other than the signer is providing verification.

(g) **Certificate of Service:** Filings shall be accompanied by a certificate of service stating the name of the individuals served, the Participants whose interests the served individuals represent, the date on which service is made, the method of service, and the addresses to which service is made. The certificate shall be executed by the individual who caused the service to be made.

1.2.4 Service

(a) **Service List:** For each proceeding, the Clerk shall prepare and maintain a list showing the name, address, telephone number, and facsimile number and email address, if available, of each individual designated for service. The Hearing Officer, NERC Director of Enforcement and the Registered Entity's compliance contact as registered with the CEA, shall automatically be included on the service list.

Participants shall identify all other individuals whom they would like to designate for service in a particular proceeding in their appearances or other filings. Participants may change the individuals designated for service in any proceeding by filing a notice of change in service list in the proceeding. Participants are required to update their service lists to ensure accurate service throughout the course of the proceeding. Copies of the service list may be obtained from the Clerk.

(b) **By Participants:** Subject to the provisions of Section 1.5.10, any Participant filing a document in a proceeding must serve a copy of the document on each individual whose name is on the service list for the proceeding. Unless otherwise provided, service may be made by personal delivery, email, and deposit in the United States mail properly addressed with first class postage prepaid, registered mail properly addressed with postage

prepaid, or deposit with a private express courier service properly addressed with charges prepaid or payment arrangements made.

(c) **By the Clerk:** The Clerk shall serve all issuances of the Hearing Officer and Hearing Panel upon the members of the Hearing Panel and each individual whose name is on the service list for the proceeding. Service may be made by personal delivery, email, or deposit in the United States mail properly addressed with first class postage prepaid, or registered mail properly addressed with postage prepaid, or deposit with a private express courier service properly addressed with charges prepaid or payment arrangements made. The Clerk shall transmit a copy of the record of a proceeding to the CEA at the time the CCC transmits to the CEA either (1) a Notice of Penalty, or (2) a Hearing Panel final order that includes a Notice of Penalty.

(d) **Effective Date of Service:** Service by personal delivery or email is effective immediately. Service by mail or registered mail is effective upon mailing; service by a private express courier service is effective upon delivery to the private express courier service. Unless otherwise provided, whenever a Participant has the right or is required to do some act within a prescribed period after the service of a document upon the Participant, four (4) days shall be added to the prescribed period when the document is served upon the Participant by mail or registered mail.

1.2.5 Computation of Time

The time in which any action is required to be done shall be computed by excluding the day of the act or event from which the time period begins to run, and by including the last day of the time period, unless the last day is a Saturday, Sunday, legal holiday or any other day upon which the office of the CEA is closed, in which event it also shall be excluded and the date upon which the action is required shall be the first succeeding day that is not a Saturday, Sunday, legal holiday, or day upon which the office of the CEA is closed.

1.2.6 Extensions of Time

Except as otherwise provided by law, the time by which a Participant is required or allowed to act may be extended by the Hearing Officer or Hearing Panel for good cause upon a motion made before the expiration of the period prescribed. If any motion for extension of time is made after the expiration of the period prescribed, the Hearing Officer or Hearing Panel may permit performance of the act if the movant shows circumstances sufficient to justify the failure to act in a timely manner.

1.2.7 Amendments

Amendments to any documents filed in a proceeding may be allowed by the Hearing Officer or the Hearing Panel upon motion made at any time on such terms and conditions as are deemed to be just and reasonable.

1.2.8 Transcripts

(a) A full and complete record of all hearings, including any oral argument, shall be transcribed verbatim by a certified court reporter, except that the Hearing Officer may allow off-the-record discussion of any matter provided the Hearing Officer states the ruling on any such matter, and the Participants state their positions or agreement in relation thereto, on the record. The court reporter shall file a copy of each transcript with the Clerk. Upon receipt of a transcript from the court reporter, the Clerk shall send notice to the Participants stating that a transcript has been filed by the court reporter, the date or dates of the hearing that the transcript records, and the date the transcript was filed with the Clerk.

(b) Unless otherwise prescribed by the Hearing Officer, a Participant may file and serve suggested corrections to any portion of a transcript within fourteen (14) days from the date of the Clerk's notice that the transcript has been filed with the Clerk, and any responses shall be filed within ten (10) days after service of the suggested corrections. The Hearing Officer shall determine what changes, if any, shall be made, and shall only

allow changes that conform the transcript to the statements being transcribed and ensure the accuracy of the record.

(c) The CEA will pay for transcription services, for a copy of the transcript for the record and for a copy of the transcript for Staff. Any other Participant shall pay for its own copy of the transcript if it chooses to obtain one and, should any Participant seek to obtain a copy of the transcript on an expedited basis, it shall pay for the expedited transcription services.

1.2.9 Rulings, Notices, Orders and Other Issuances

Any action taken by the Hearing Officer or the Hearing Panel shall be recorded in a ruling, notice, order or other applicable issuance, or stated on the record for recordation in the transcript, and is effective upon the date of issuance unless otherwise specified by the Hearing Officer or the Hearing Panel. All notices of hearings shall set forth the date, time and place of hearing.

1.2.10 Location of Hearings and Conferences

All hearings and oral arguments shall be held at the principal office of the CEA unless the Hearing Officer or Hearing Panel designates a different location.

1.2.11 Participant Participation

Participants may appear at any hearing via teleconference subject to the approval of the Hearing Officer and, in the event of oral argument, the Hearing Panel, except as required by Section 1.6.6. Staff may participate and be represented by counsel in hearings, and shall have the rights and duties of any Participant.

1.2.12 Interventions

(a) The Respondent(s) and Staff shall be Participants to the proceeding. Unless otherwise authorized by the Hearing Panel or by FERC, no other Persons shall be permitted to intervene or otherwise become a Participant to the proceeding.

(b) The Hearing Panel may allow a Person to intervene only if the Hearing Panel determines that the Person seeking intervention has a direct and substantial interest in the outcome of the Alleged Violation, proposed Penalty or sanction, proposed Mitigation Plan or Mitigating Activities, or Remedial Action Directive that is the subject of the proceeding. Examples of a direct and substantial interest in the outcome shall include that the person seeking intervention:

(1) has received a Notice of Alleged Violation or a Remedial Action Directive involving the same Reliability Standard requirement(s) and arising out of the same event or occurrence as the existing Respondent(s) that is the subject of the proceeding, or

(2) will or may be contractually or legally liable to the original Respondent(s) for payment of all or a portion of the proposed Penalty or sanction that is the subject of the proceeding, provided, that after the Person seeking intervention sufficiently demonstrates it will or may be contractually or legally liable for payment of all or a portion of the proposed Penalty or sanction to be granted intervention, the Person granted intervention and the existing Respondents will not be allowed to litigate in the proceeding whether the Person granted intervention is contractually or legally liable for payment of all or a portion of the proposed Penalty or sanction or the amount of the proposed Penalty or Sanction for which the Person granted intervention is or may be liable.

That the Person seeking intervention has received a Notice of Alleged Violation for the same Reliability Standard Requirement(s) as the original Respondent(s) but arising out of a different event or occurrence; or seeks to intervene to advocate an interpretation of the Reliability Standard

Requirement(s) or provision(s) of the Sanction Guidelines, that are at issue in the proceeding, without more, shall not constitute a direct and substantial interest in the outcome and shall not be grounds on which the Hearing Panel may allow the Person to intervene.

(c) A Person seeking intervention shall do so by filing a motion to intervene with the Clerk. The motion shall state the Person's interest in sufficient factual detail to demonstrate that the Person should be allowed to intervene pursuant to Section 1.2.12(b). The motion to intervene shall also state the Person's agreement to maintain the confidential and non-public nature of the hearing, including all pleadings and other documents filed or exchanged in connection with the request for intervention. Any facts alleged in, or offers of proof made in, the motion to intervene shall be supported by affidavit or verification.

(d) The Clerk shall promptly provide copies of the motion to intervene to the Hearing Officer and the Participants. The Hearing Officer shall promptly set a response period, not to exceed seven days, within which the Participants may file responses to the motion to intervene. Within seven (7) days following the end of the response period, the Hearing Officer shall issue a recommendation to the Hearing Panel as to whether or not the motion to intervene should be granted.

(e) The Hearing Panel may, within seven (7) days following the date of the Hearing Officer's recommendation, issue a decision granting or denying the motion to intervene. If the Hearing Panel does not issue a decision granting or denying the motion to intervene within seven (7) days following the date of the Hearing Officer's recommendation, the Hearing Officer's recommendation shall become the decision of the Hearing Panel and the motion to intervene shall be deemed granted or denied by the Hearing Panel in accordance with the Hearing Officer's recommendation.

(f) The Hearing Officer, on motion of a Participant or on his or her own motion, or the Hearing Panel, on recommendation by the Hearing Officer or its own motion, may stay or suspend the proceeding while a request to intervene, including a request to intervene filed directly with FERC, and including any appeal of the grant or denial of the request to intervene, is being resolved.

(g) A Person allowed to intervene and become a Participant to a proceeding shall be designated as a Respondent and deemed to be aligned with the existing Respondent(s), unless the Hearing Panel, in the decision granting intervention, states that the Person allowed to intervene shall be deemed to be aligned with another Participant to the proceeding.

(h) A Person may appeal a decision of the Hearing Panel denying the Person's motion to intervene, and the Staff, the Respondent or any other Participant may appeal a decision granting or denying a motion to intervene, in accordance with Section 414 of the NERC Rules of Procedure. A notice of appeal shall be filed with the NERC Director of Enforcement no later than seven (7) days following the date of the decision of the Hearing Panel granting or denying the motion to intervene.

1.2.13 Proceedings Closed to the Public

No hearing, oral argument, or meeting of the Hearing Panel shall be open to the public, and no notice, ruling, order, or any other issuance of the Hearing Officer or Hearing Panel, or any transcript, made in any proceeding shall be publicly released unless the ERO (within the U.S., in accordance with the authorization previously granted by FERC to release information about a non-public proceeding) or FERC (in the case of U.S.-related information) or another Applicable Governmental Authority (in the case of non-U.S.-related information) determines that public release is appropriate. Only the members of the Hearing Panel, the Participants, the Hearing Officer and the Technical Advisors, if any, shall be allowed to participate in or obtain information relating to a proceeding.

1.2.14 Docketing System

The Clerk shall maintain a system for docketing proceedings. A docketed proceeding shall be created upon the filing of a request for a hearing. Unless NERC provides a different docketing system that will be used uniformly, docket

numbers shall be assigned sequentially beginning with a two digit number that relates to the last two digits of the year in which the docket is initiated, followed by a dash ("-"), followed by the letters "[RE]", followed by a dash ("-"), followed by a four digit number that will be "0001" on January 1 of each calendar year and ascend sequentially until December 31 of the same calendar year.

1.2.15 Representations Deemed to be made in All Pleadings

A Participant presenting any pleading to the Hearing Officer or Hearing Panel shall be deemed to certify that to the best of the Participant's knowledge, information and belief, formed after and based on an inquiry that is reasonable under the circumstances, that:

(a) the factual allegations set forth in the pleading have or will have support in the evidence or the Participant believes they will have support in the evidence after reasonable opportunity for further investigation or discovery;

(b) the denials in the pleading of factual allegations made by another Participant are warranted by or will be warranted by the evidence or, if specifically so identified, are reasonably based on belief or on a lack of information;

(c) the claims, defenses and other contentions set forth in the pleading are warranted based on the applicable Reliability Standard Requirement(s) or Rules of Procedure provisions; and

(d) the pleading is not being presented for any improper purpose, such as to harass, cause unnecessary delay, or needlessly increase the cost of the hearing or the cost incurred by any Participant.

1.2.16 Hold Harmless

A condition of a Participant invoking these Hearing Procedures and participating in a hearing is that the Participant agrees that the CEA and CCC, including without limitation its Members, Board of Directors or Trustees, Compliance Committee, any other committees or subcommittees, Staff, contracted employees, Hearing Panel members, Hearing Officers and Technical Advisors, shall not be liable, and shall be held harmless against the consequences of, or any action or inaction arising out of, the hearing process, or of any agreement reached in resolution of a dispute or any failure to reach agreement as a result of a proceeding. This "hold harmless" provision does not extend to matters constituting gross negligence, intentional misconduct, or breach of confidentiality.

1.3 Initiation of the Hearing Process

1.3.1 Registered Entity's Option to Request a Hearing

(a) Except when contesting a Remedial Action Directive pursuant to Section 1.9 of these Hearing Procedures, a Registered Entity may file a statement, in accordance with Section 1.3.1(e), with the CCC requesting a hearing if either:

(1) the Registered Entity files a response to a Notice of Alleged Violation that contests either the Alleged Violation, the proposed Penalty, or both; or

(2) the Staff submits to the Registered Entity a statement rejecting the Registered Entity's proposed revised Mitigation Plan or Mitigating Activities submitted after Staff rejected the Registered Entity's initial proposed Mitigation Plan or Mitigating Activities.

(b) A Registered Entity must file its hearing request within forty (40) days after:

(1) the Registered Entity files its response to the Notice of Alleged Violation; or

(2) the Staff submits to the Registered Entity its statement identifying a disagreement with the Registered Entity's proposed Mitigation Plan or Mitigating Activities, whichever is applicable.

(c) If the Registered Entity does not file a hearing request within the period set forth in this Section, then the Registered Entity will be deemed to have agreed and waived any objection to the proposed Penalty, the Alleged Violation or the Staff's rejection of the revised Mitigation Plan or Mitigating Activities, whichever is applicable.

(d) In accordance with Section 5.3 of the CMEP, a Notice of Alleged Violation issued to a Registered Entity or a CEA Staff statement setting forth its rejection of a Registered Entity's proposed revised Mitigation Plan or Mitigating Activities shall clearly state that the Registered Entity has the option to contest the Alleged Violation, proposed Penalty, or both, or the Staff's rejection of the proposed revised Mitigation Plan or Mitigating Activities, using either the shortened hearing procedure pursuant to Section 1.3.4 or the general hearing procedure described in Sections 1.4 to 1.7.

(e) The Registered Entity's statement requesting a hearing shall:

(1) contain a plain and concise statement of the facts and arguments supporting the Registered Entity's position, as applicable, that it did not violate the Reliability Standard Requirement(s) set forth in the Notice of Alleged Violation, that the proposed Penalty or sanction is too high and should be reduced, or that the Registered Entity's proposed Mitigation Plan or Mitigating Activities should be approved;

(2) state the relief that the Registered Entity requests the Hearing Panel to grant; and

(3) state whether the Registered Entity requests the shortened hearing procedure or the general hearing procedure.

The Registered Entity's statement may set forth two or more alternative grounds on which the Registered Entity bases its position, as applicable, that it did not violate the Reliability Standard Requirement(s) set forth in the Notice of Alleged Violation, that the proposed Penalty or sanction is too high and should be reduced, or that the Registered Entity's proposed Mitigation Plan or Mitigating Activities should be approved.

(f) If the Registered Entity (or any Respondent if there are more than one Respondent) requests the general hearing procedure, the general hearing procedure shall apply. If the Registered Entity (or all Respondents if there are more than one Respondent) requests the shortened hearing procedure, Staff and any other Participants shall submit a filing within five (5) days of the Registered Entity's hearing request that states whether Staff or such other Participant agrees to use the shortened hearing procedure. If Staff or another

Participant makes a filing requesting the general hearing procedure, then the general hearing procedure shall apply; otherwise the shortened hearing procedure requested by the Registered Entity or entities shall be used. Once either the general or shortened hearing procedure has been selected, the Participants shall not be allowed to revert to the non-selected hearing procedure unless the Participants mutually agree.

(g) **A Registered Entity shall attach to its request for hearing** whichever of the following are applicable:

(1) The Registered Entity's Self-Report of a violation;

(2) The Notice of Alleged Violation and the Registered Entity's response thereto; and/or

(3) **The** Registered Entity's proposed revised Mitigation Plan or Mitigating Activities and the Staff's statement rejecting the proposed revised Mitigation Plan or Mitigating Activities.

1.3.2 Staff's Response to Request for Hearing

(a) If the Registered Entity requests that the shortened hearing procedure be used, the Staff shall file a response stating whether it agrees to the use of the shortened hearing procedure.

(b) If the Registered Entity requests that its proposed revised Mitigation Plan or Mitigating Activities should be approved, the Staff shall file a response stating the Staff's position as to why the Registered Entity's proposed revised Mitigation Plan or Mitigating Activities should not be approved and setting forth any additional terms that the Staff believes should be included in the Mitigation Plan or Mitigating Activities.

(c) If the Registered Entity does not request that the shortened hearing procedure be used and does not request that the Registered Entity's proposed revised Mitigation Plan or Mitigating Activities should be approved, the Staff may, but is not required to, file a response stating, as applicable, the basis for the Staff's position that the Registered Entity violated the Reliability Standard Requirement(s) specified in the Notice of Alleged Violation or that the proposed Penalty or sanction is appropriate under the Sanction Guidelines and should not be reduced.

(d) Any response by the Staff required or permitted by this Section shall be filed within fifteen (15) days after the date the request for hearing was filed, unless the Hearing Officer or Hearing Panel allows a longer time to file the response.

1.3.3 Notice of Hearing

(a) The Clerk shall issue a notice of hearing not less than sixteen (16) days, and not more than twenty-one (21) days, after the Registered Entity files its request for hearing.

(b) The notice of hearing shall state whether the shortened hearing procedure or the general hearing procedure will be used.

(c) The notice of hearing shall identify the Hearing Officer and the date, time and place for the initial prehearing conference.

(1) If the shortened hearing procedure is to be used, the initial prehearing conference shall be set for a date within seven (7) days following the date of the notice of hearing.

(2) If the general hearing procedure is to be used, the initial prehearing conference shall be set for a date within fourteen (14) days following the date of the notice of hearing.

1.3.4 Shortened Hearing Procedure

The shortened hearing procedure shall be as set forth in this Section. The rules applicable to the general hearing procedure shall apply to the shortened hearing procedure unless the context of such a rule is inconsistent with the

procedure set forth in this Section or otherwise renders it inapplicable to the shortened hearing procedure. The rules concerning ex parte communications in Section 1.4.7 are hereby expressly made applicable to the shortened hearing procedure under this Section.

The Hearing Panel shall use a Hearing Officer to preside over the shortened hearing procedure in accordance with Section 1.4.2. No testimonial hearing will be held in the shortened hearing procedure and the Participants will not present witness testimony or file briefs, except that briefs on exceptions and briefs in reply to exceptions may be allowed pursuant to subsection (g). Instead, the following events shall take place within the following periods:

(a) The initial prehearing conference shall be held within seven (7) days after the date on which the notice of hearing is issued. In addition to any other matters set forth in Section 1.5.2 that may apply, the initial prehearing conference will be used to develop a schedule for the preparation and submission of comments in accordance with subsections (c) through (e).

(b) Within ten (10) days after the date on which the notice of hearing is issued, Staff shall make documents available to the Registered Entity for inspection and copying pursuant to Section 1.5.7.

(c) Within twenty-one (21) days after the initial prehearing conference, the Staff shall file:

(1) initial comments stating Staff's position on all issues and the rationale in support of its position, including all factual and legal arguments;

(2) all Documents that Staff seeks to introduce in support of its position that have not already been submitted in the proceeding; and

(3) a verification attesting to the truthfulness of the facts alleged in the filing.

(d) Within fourteen (14) days of Staff's initial comment filing pursuant to subsection (c), the Registered Entity shall file:

(1) responsive comments stating the Registered Entity's position on all issues and the rationale in support of its position, including all factual and legal arguments, which also may respond to Staff's initial comments;

(2) all Documents that the Registered Entity seeks to introduce in support of its position that have not already been submitted in the proceeding; and

(3) a verification attesting to the truthfulness of the facts alleged in the filing.

(e) Within seven (7) days after the Registered Entity's responsive comment filing, Staff shall file reply comments that shall be limited in scope to responding to the Registered Entity's responsive comments and be supported by a verification attesting to the truthfulness of the facts alleged in the filing. Staff shall not submit any additional Documents in support of its position as part of this filing except upon motion and good cause shown. If Staff is allowed to file additional Documents in support of its position based upon such a motion, the Registered Entity shall have the right to file additional Documents in support of its position that are responsive to the additional Documents that Staff is allowed to file provided that any additional Registered Entity filing also shall be verified.

(f) The Hearing Officer shall issue an initial opinion within twenty-one (21) days after the Staff's reply comments filing or any additional filing by the Registered Entity pursuant to subsection (e).

(g) If either Participant requests, the Hearing Officer shall allow each Participant to file, within seven (7) days after the Hearing Officer's initial opinion, exceptions to the Hearing Officer's initial opinion in a brief designated "brief on exceptions" in accordance with Section 1.7.5 and within seven (7) days thereafter, a reply brief designated "brief in reply to exceptions."

(h) The Hearing Panel shall strive, but is not required, to issue a final order within one hundred twenty (120) days of the notice of hearing. The Hearing Panel may extend this deadline for good cause and shall provide written notice of any extension to all Participants.

The Hearing Officer or Hearing Panel may modify any period set forth within this Paragraph as warranted by the circumstances but it will be the objective of the Hearing Panel to issue the final order within one hundred twenty (120) days of the notice of hearing.

1.4 General Hearing Procedure

1.4.1 [Intentionally Left Blank]

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1.4.2 Hearing Officer

(a) The CCC shall use a Hearing Officer to preside over each hearing conducted pursuant to these Hearing Procedures, provided that the Hearing Officer's actions shall be subject to the authority of the Hearing Panel as set forth in Section 1.4.3. Members of the Hearing Panel may attend any aspect of the hearing.

(b) The Hearing Officer is responsible for the conduct of the hearing, including administering the hearing from the initial prehearing conference through the issuance of the Hearing Officer's initial opinion, any administrative hearing functions thereafter, and submission of the matter to the Hearing Panel for final decision through the presentation to the Hearing Panel of an initial opinion. The Hearing Officer shall have those duties and powers necessary to those ends, consistent with and as further enumerated in these Hearing Procedures, including the following:

(1) To administer oaths and affirmations;

(2) To schedule and otherwise regulate the course of the hearing, including the ability to call to recess, reconvene, postpone or adjourn a hearing;

(3) Consistent with any timing or deadline requirements imposed by these Hearing Procedures or by applicable law, to separate any issue or group of issues from other issues in a proceeding and treat such issue(s) as a separate phase of the proceeding;

(4) Consistent with any timing or deadline requirements imposed by these Hearing Procedures or by applicable law, to modify any time period, if such modification is in the interest of justice and will result in no undue prejudice to any other Participant;

(5) To supervise and issue orders concerning discovery;

(6) To conduct prehearing conferences, status hearings, and evidentiary hearings;

(7) To hear argument on all objections, motions and other requests, and to rule upon all objections, motions and other requests that do not result in the final determination of the proceeding;

(8) To rule on and receive evidence;

(9) To call upon a Participant to produce further evidence that is material and relevant to any issue;

(10) To issue protective orders pursuant to Section 1.5.10;

(11) To issue initial opinions; and

(12) To ensure that hearings are conducted in a full, fair, and impartial manner, that order is maintained and that unnecessary delay is avoided in the disposition of the proceedings.

The CCC shall disclose the employment history and professional affiliations of the Hearing Officer within two (2) days of the Hearing Officer's assignment to the proceeding, and Participants to the hearing may raise objections to the Hearing Officer's participation in accordance with Section 1.4.5.

1.4.3 Hearing Panel

(a) The CCC shall not have a standing Hearing Panel. When a hearing is to be conducted, the CCC shall select five members to serve as the adjudicatory panel for that hearing. Members to serve on the Hearing Panel shall be selected by vote of a valid quorum of the CCC. Voting members of the CCC at arm's length from parties to the hearing may be nominated or volunteer to stand for selection to the Hearing Panel. One or more alternates may also be selected if the CCC deems appropriate for the circumstances. A member may serve on more than one Hearing Panel concurrently. A Hearing Panel is disbanded upon conclusion of the hearing proceedings for which it was formed.

(b) The composition of the Hearing Panel, after any recusals or disqualifications, shall be such that no two industry sectors may control, and no single industry sector may veto, any decision of the Hearing Panel on any matter brought before it for decision. "Hearing Panel" means the five person Hearing Panel established as set forth in the CCC Charter on a case by case basis and that is responsible for adjudicating a matter as set forth in Section 1.1.1 above.

(c) The Hearing Panel is vested with the authority to issue a final order resolving the issue(s) in all cases. To that end:

(1) Upon receiving a filing by a Participant, the Clerk shall promptly send a notice to the members of the Hearing Panel identifying the date of the filing and the Participant making the filing and briefly describing the nature of the filing. Any member of the Hearing Panel may request of, and shall receive from, the Clerk, a copy of any filing by a Participant. The Hearing Panel shall not receive Documents made available by Staff for inspection and copying by the Respondent, or other responses to discovery between the Participants, unless such Documents are placed into the record pursuant to Section 1.6.7.

(2) The Clerk shall send all issuances of the Hearing Officer to the members of the Hearing Panel.

(3) The Hearing Panel or any individual member thereof may, but is not required to, attend any prehearing conference, status hearing or evidentiary hearing, and/or to submit questions to the Hearing Officer to submit to a Participant or any witness at any hearing. At any prehearing conference or hearing attended by a member of the Hearing Panel, any member of the Hearing Panel may ask questions directly of any Participant or witness.

(4) The Hearing Panel shall have the same authority as the Hearing Officer, as set forth in these Hearing Procedures, to require the Participants or any individual Participant to: (i) address a specific issue in testimony, evidence or briefs; (ii) present oral argument on an issue; (iii) file pre-evidentiary hearing memorandums; or (iv) produce further evidence that is material and relevant to any issue. To this end, the Hearing Panel shall be entitled to issue questions or requests for information to any Participant or any witness at any time until the issuance of a final order.

(5) **To the extent that the Hearing Panel disagrees with any issuance or ruling of the Hearing Officer, it may, on its own motion or upon petition for interlocutory review meeting the requirements of Section 1.4.4, reverse or modify the issuance or ruling in whole or in part, or take any other action as may be appropriate.** The Hearing Panel shall resolve the issue(s) in every hearing through the issuance of a final order. In issuing a final order, the Hearing Panel shall consider the Hearing Officer's initial opinion but shall have the authority to reject, modify, or approve the initial opinion in whole or in part.

1.4.4 Interlocutory Review

(a) A Participant shall be allowed to seek interlocutory review by the Hearing Panel of any ruling of the Hearing Officer where the ruling for which interlocutory review is sought presents an extraordinary circumstance

which makes prompt review necessary to prevent prejudice to a Participant's ability to present its position in the proceeding. Failure to seek such review shall not operate as a waiver of any objection to such ruling.

(b) Unless good cause is shown or unless otherwise ordered by the Hearing Officer or the Hearing Panel, the Participant seeking review shall file a petition for interlocutory review within fourteen (14) days after the date of the action that is the subject of the petition. The petition shall contain, in a separately identified section, a demonstration that the ruling for which interlocutory review is sought presents an extraordinary circumstance which makes prompt review necessary to prevent prejudice to the Participant's ability to present its position in the proceeding. The petition shall be filed with any offer of proof and supported by references to the record, or by affidavit if based on facts that do not appear in the record. Responses to petitions for interlocutory review shall be filed within seven (7) days after service of the petition. No replies to responses shall be allowed.

(c) The Hearing Officer shall file a report to the Hearing Panel within fourteen (14) days from the filing of the petition. The Hearing Officer's report shall set forth the relevant facts and other background information relating to the ruling on which interlocutory review is sought, the basis for the Hearing Officer's ruling, a summary of the Participants' arguments on the petition for interlocutory review, and the recommendation of the Hearing Officer for the disposition of the petition by the Hearing Panel.

(d) On review of a Hearing Officer's ruling, the Hearing Panel may affirm or reverse the ruling in whole or in part, and may take any other just and reasonable action with respect to the ruling, such as declining to act on an interlocutory basis. The Hearing Panel may reject the petition for interlocutory review on the grounds that the ruling for which review is sought does not present an extraordinary circumstance which makes prompt review necessary to prevent prejudice to a Participant's ability to present its position in the proceeding, without considering or ruling on the substance of the petitioner's arguments.

(e) Issuance of a ruling on a petition for interlocutory review shall require (i) a quorum (as defined in Section 1.7.8) of the Hearing Panel, and (ii) a majority vote of the members of the Hearing Panel voting on the final order (in which the number of members voting shall not be less than a quorum). Petitions to rehear or reconsider the Hearing Panel's action taken on interlocutory review shall not be allowed. Filing and disposition of a petition for interlocutory review of a ruling of the Hearing Officer shall not suspend or otherwise delay a hearing or any other scheduled dates in the proceeding except as authorized by the Hearing Officer or the Hearing Panel based on a finding of exceptional circumstances.

(f) A non-Participant that has been ordered by the Hearing Officer pursuant to Section 1.5.8 to produce or provide Documents, information or testimony, and has failed to obtain the relief sought from the Hearing Officer through filing objections to or a motion to quash the order, shall also be entitled to seek interlocutory review by the Hearing Panel of the Hearing Officer's order, with respect to (i) whether the non-Participant is within the class of Persons subject to such orders pursuant to Section 1.5.8, and (ii) the reasonableness of the Hearing Officer's order to produce or provide Documents, information or testimony.

1.4.5 Disqualification

(a) A Hearing Officer, Technical Advisor or member of the Hearing Panel shall recuse himself or herself from a proceeding if participation would violate NERC's applicable conflict of interest policy.

(b) Any Participant may file a motion to disqualify or for recusal of a Hearing Officer, Technical Advisor or member of the Hearing Panel from a proceeding on grounds of a conflict of interest, an ex parte communication prohibited by Section 1.4.7, or the existence of other circumstances that could interfere with the impartial performance of his or her duties. The Participant shall set forth and support its alleged grounds for disqualification by affidavit. A motion for disqualification shall be filed within fifteen (15) days after the later of: (1) the time when the Participant learns of the facts believed to constitute the basis for

disqualification; or (2) the time when the Participant is notified of the assignment of the Hearing Officer or Technical Advisor.

(c) The Hearing Officer shall issue a proposed ruling for the Hearing Panel's consideration upon the filing of a motion for disqualification unless the Hearing Officer is the subject of the motion. The Hearing Panel, without the participation of any member who is the subject of the motion, shall issue a final ruling on the motion. If the Hearing Officer recuses himself or herself or is disqualified, the Hearing Panel will appoint a replacement Hearing Officer. To ensure fairness to the Participants and expedite completion of the proceeding when a replacement Hearing Officer is appointed after a hearing has commenced, the replacement Hearing Officer may recall any witness or may take other steps necessary to ensure familiarity with any part or all of the record.

(d) If a quorum (as defined in Section 1.7.8) of the Hearing Panel does not remain after any recusals and rulings on motions for disqualification, then the CCC shall appoint at least the number of new members to the Hearing Panel necessary to create a quorum. The new member(s) shall serve on the Hearing Panel through the conclusion of the proceeding but not thereafter. Any new member of the Hearing Panel shall be subject to the provisions applicable herein to all Hearing Panel members.

1.4.6 Technical Advisor

(a) The Hearing Officer and/or the Hearing Panel may elect to use one or more Technical Advisors to assist in any proceeding. Such an election may be made at any time during the course of a proceeding. Any Staff member who serves as a Technical Advisor shall not have been involved in or consulted at any time in regard to any Staff investigation, determination of a Possible Violation, Alleged Violation or Penalty, or assessment of a Registered Entity's proposed Mitigation Plan or Mitigating Activities that resulted in the proceeding in which technical advice would be rendered, and shall not be a member of Staff participating in the proceeding on which such technical advice would be rendered.

(b) If the Hearing Officer or Hearing Panel uses a Technical Advisor to assist in any hearing, the Hearing Officer or Hearing Panel shall disclose the identity, employment history and professional affiliations of the Technical Advisor within two (2) days of the Technical Advisor's assignment to the proceeding, and Participants to the hearing may raise objections to the Technical Advisor's participation in accordance with Section 1.4.5.

1.4.7 No Ex Parte Communications

(a) Once a Registered Entity requests a hearing pursuant to Section 1.3.1:

(1) neither the Hearing Panel, the Hearing Officer, nor the Technical Advisor(s), if any, may communicate either directly or indirectly with any Person concerning any issue in the proceeding outside of the hearing process; except that

(2) the Hearing Panel, the Hearing Officer, and the Technical Advisor(s), if any, may communicate outside of the hearing process either directly or indirectly with a Participant or a Participant's representative:

i. in writing if the writing is simultaneously provided to all Participants;

ii. orally if a representative for every Participant is present in person or by telephone; or

iii. subject to the requirement that the substance of any ruling on any issue discussed shall be memorialized on the record or by the issuance of a notice or ruling, and that any Participant objecting to the ruling shall have the opportunity to state its objection on the record.

(b) Exceptions

(1) The proscription in subsection (a)(1) does not prohibit members of the Staff from communicating with the Registered Entity, and representatives, agents or employees thereof on any topic, provided that any member of the Staff involved in any such communication relating to the subject matter of the proceeding may not be, and may not subsequently serve as, a Technical Advisor.

(2) The proscription in subsection (a)(1) does not prohibit communications between or among members of the Hearing Panel, the Hearing Officer, and any Technical Advisor.

(3) The proscription in subsection (a)(1) does not prohibit communications between the Hearing Officer or members of the Hearing Panel to the Clerk for the purpose of transmitting documents, giving instructions to the Clerk, or discussing scheduling and other procedural matters relating to the proceeding.

(4) The proscription in subsection (a)(1) does not prohibit communications between or among the Clerk, the Hearing Panel and representatives of the CEA for purposes of establishing the hearing forum.

(c) Any member of the Hearing Panel, the Hearing Officer or any Technical Advisor who receives or who makes or knowingly allows a communication prohibited by this Section shall, within seven (7) days of the communication, file and serve on the Participants in the proceeding a notice of ex parte communication setting forth the date, time and place of communication, a summary of the substance and nature of the communication and all responses thereto, and a list of each Person who made or received the communication and, if the communication or any response thereto was in writing, a copy of the written communication shall be attached.

1.4.8 Appearances

(a) Participants shall file written appearances within seven (7) days after the notice of hearing is issued. A Participant's written appearance shall identify the name(s) of each individual authorized to represent the Participant in the proceeding exclusive of witnesses. An individual may appear on his or her own behalf. A corporation, limited liability company, association, partnership, or governmental body may appear by any bona fide officer or designee who has the authority to act on behalf of the Participant. A Participant also may appear by an attorney.

(b) A Participant's written appearance shall state, with respect to each individual that the Participant identifies for service, the individual's name, address, telephone number, and facsimile number and email address, if available, where service shall be made.

(c) A Participant may withdraw any individual from the Participant's representation or otherwise change the identity of individuals authorized to represent the Participant in a proceeding by filing a notice of a change in service list.

(d) Any attorney appearing on behalf of a Participant shall be licensed to practice law and in good standing before the Supreme Court of the United States or the highest court of any State, territory of the United States or the District of Columbia. All representatives appearing before the Hearing Panel or Hearing Officer shall conform to the standards of ethical conduct required of practitioners before the courts of the United States.

(e) Individuals representing Participants in any hearing also shall enter their appearances at the beginning of the hearing by stating their names, addresses, telephone numbers, and email addresses orally on the record.

1.4.9 Failure to Appear or Exercise Diligence

The failure of any Participant to appear during any hearing without good cause and without notification may be grounds for dismissal or deciding against the interests of such Participant.

1.4.10 Consolidation of Proceedings

(a) In the event that more than one Registered Entity receives a Notice of Alleged Violation for the same event or occurrence, and each Registered Entity selects the general hearing procedure described in Sections 1.4 to 1.7, the Hearing Panel on its own motion or on motion of a Participant may exercise its discretion to examine the actions of all such Registered Entities in a single proceeding as long as an initial opinion has not been rendered by the Hearing Officer pursuant to Section 1.7.4 in any proceeding to be consolidated.

(b) A Participant may file a motion to consolidate into a single proceeding alleged violations of different Reliability Standards against a single Respondent, and related contests of Penalties, Mitigation Plan or Mitigating Activities, arising out of the same event or occurrence. Such consolidation may be allowed in the discretion of the Hearing Officer or Hearing Panel, as applicable.

1.5 Prehearing Procedure

1.5.1 [Intentionally Left Blank]

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1.5.2 Prehearing Conference

(a) The Hearing Officer shall hold at least one prehearing conference, which may be the initial prehearing conference or a subsequently scheduled prehearing conference, in order to:

(1) Preliminarily identify the issues and discuss the anticipated form of the hearing;

(2) Discuss a schedule for any discovery to be conducted and address any discovery issues that are raised at that time;

(3) Explore the possibility of obtaining admissions of fact and of the authenticity of documents that would avoid unnecessary proof;

(4) Develop a schedule for the preparation and submission of evidence and witness testimony, including the disclosure of witnesses and exhibits and whether the use of pre-filed testimony may not be appropriate, in advance of the evidentiary hearing;

(5) Develop a schedule or schedules for any anticipated motions;

(6) Schedule a date(s) for the evidentiary hearing, which shall be within ninety (90) days of the prehearing conference described in this subsection, unless a different date or dates is specified by the Hearing Officer or the Hearing Panel and with the consent of all Participants or for good cause shown; and

(7) Address such other matters as may aid in the simplification of the evidence and disposition of the proceeding.

(b) The Hearing Officer shall also hold a final prehearing conference prior to the evidentiary hearing, for the purpose of discussing:

(1) the anticipated duration of the hearing;

(2) the scheduling of witnesses' appearances to testify;

(3) the issues anticipated to be presented at the hearing;

(4) whether prehearing memoranda should be filed and if so, the schedule; and

(5) any other matters identified by the Hearing Officer for the management of the evidentiary hearing.

Participants may submit to the Hearing Officer, at least ten (10) days prior to the scheduled date of the final prehearing conference, a proposed list or lists of matters to be discussed at the final prehearing conference.

1.5.3 Summary Disposition

(a) **Availability:** A Hearing Officer, on the Hearing Officer's own motion or on the motion of a Participant, may issue an initial opinion granting, in whole or in part, summary disposition if it appears that there are no issues of material fact and a Participant is entitled to issuance of a final order in its favor.

(b) **Motion for Summary Disposition and Responses**

(1) A Participant moving for summary disposition must clearly identify the material facts that are not in dispute, demonstrate that there are no other material facts in dispute, and demonstrate that on the basis of the undisputed material facts, the Participant is entitled to issuance of a final order in its favor.

(2) A Participant opposing a motion for summary disposition must clearly identify in its response to the motion the material facts that the Participant contends remain in dispute, and/or explain why the moving Participant is not entitled to issuance of a final order in its favor even though there are no disputed issues of material fact.

(c) **Summary Disposition on the Hearing Officer's Own Motion:** If the Hearing Officer is considering summary disposition in the absence of a Participant motion, the Hearing Officer shall request the Participants to identify in writing any issues of material fact and to comment on the proposed disposition. Factual information in the Participants' comments shall be supported by affidavit. Following review of the Participants' comments, if it still appears to the Hearing Officer that there are no genuine issues of material fact, the Hearing Officer may proceed without an evidentiary hearing. The Hearing Officer shall, however, allow the Participants the opportunity to file briefs.

(d) **Hearing Officer's Initial Opinion Granting Summary Disposition:** When the Hearing Officer issues an initial opinion granting summary disposition in whole or in part, the ruling shall set forth the rationale for the grant. An initial opinion of the Hearing Officer granting summary disposition shall be confirmed, rejected, or modified in a final order issued by the Hearing Panel.

1.5.4 Status Hearings

Any Participant may request, and the Hearing Officer may call, a status hearing at any time subsequent to the initial prehearing conference to address issues that have arisen between the Participants or other matters relevant to the conduct of the hearing. Such issues may include, but are not limited to, discovery disputes and scheduling matters. A Participant requesting a status hearing to resolve a dispute shall include in its request a certification that it has made a good faith effort to resolve the dispute with the other Participant(s) before requesting the status hearing. The Hearing Officer shall direct the Clerk to issue a notice of status hearing that sets forth the date, time, and place for the hearing, and that identifies the matters to be addressed at the hearing.

1.5.5 Motions and Responses

(a) Unless otherwise provided in these Hearing Procedures or by the procedural schedule established by the Hearing Officer or Hearing Panel, a Participant may file a motion at any time requesting any relief as may be appropriate. Unless the Hearing Officer allows a motion to be made orally on the record, motions shall be filed in writing. Motions based on facts that do not appear on the record shall be supported by affidavit.

(b) Unless otherwise specified by the Hearing Officer or Hearing Panel, responses to motions shall be filed within fourteen (14) days after service of the motion, and replies to responses shall be filed within seven (7) days after service of the responses. A Hearing Officer or Hearing Panel may deny dilatory, repetitive, or frivolous motions without awaiting a response. Unless otherwise ordered by a Hearing Officer or Hearing Panel, the filing of a motion does not stay the proceeding or extend any scheduled dates in the proceeding.

1.5.6 Experts

(a) A Participant may employ an expert(s) to testify or consult in a proceeding. Any expert utilized in either capacity shall sign an agreement evidencing the expert's understanding and acknowledgement of the non-public nature of the proceeding and that unauthorized public disclosure of information obtained in connection with the expert's participation in the proceeding is prohibited.

(b) The Participant employing the expert shall propose the agreement for approval by a motion, and its approval shall be subject, in addition to consideration of any objections by other Participants, to ensuring that appropriate safeguards are maintained to protect the confidentiality of the proceeding and the information disclosed therein.

1.5.7 Inspection and Copying of Documents in Possession of Staff

(a) Documents to be Available for Inspection and Copying

(1) Within twenty-five (25) days after the date the request for hearing is filed, Staff shall make available for inspection and copying by the other Participants, all Documents prepared or obtained by Staff through or in connection with any compliance monitoring processes that led to the institution of proceedings. Such Documents shall include but are not limited to:

i. requests for information to the Respondent;

ii. every written request, including e-mail, directed to persons not employed by the CEA to provide information or documents or to be interviewed;

iii. the Documents provided in response to any such requests described in (i) and (ii) above;

iv. all transcripts of testimony recorded during the Staff investigation and all exhibits to the transcript;

v. all other Documents obtained from the Respondent; and

vi. all other Documents obtained from persons not employed by the CEA.

The sole grounds on which Staff is authorized to withhold Documents from inspection and copying are the bases set forth in Section 1.5.7(b); provided, however, that the Documents made available for inspection and copying need not include (i) exact copies of Documents the Respondent previously provided to Staff, and (ii) any Documents provided to the Respondent with or as part of the Notice of Alleged Violation, Notice of Penalty, assessment of proposed Mitigation Plan or Mitigating Activities or Remedial Action Directive.

(2) Where there are Participants in a proceeding in addition to a single Respondent and Staff, the Hearing Officer or Hearing Panel shall oversee the Staff's designation of Documents to be produced to such other Participants and the development, execution and enforcement of any protective order deemed necessary.

(3) Staff shall promptly inform the Hearing Officer and each other Participant if, after the issuance of a notice of hearing, requests for information are issued by Staff related to the same compliance monitoring process(es) that led to the institution of the proceeding. If Staff receives Documents pursuant to a request for information after Staff has made Documents available for inspection and copying as set forth in subsection (a)(1), the additional Documents shall be made available to the Participants not later than fourteen (14) days after Staff receives such Documents. If a date for the evidentiary hearing has been scheduled, Staff shall make the additional Documents available to the other Participants not less than ten (10) days before the evidentiary hearing. If Staff receives such Documents ten or fewer days before the evidentiary hearing is scheduled to begin or after the evidentiary hearing begins, Staff shall make the additional Documents available immediately to the other Participants.

(4) Nothing in subsection (a)(1) shall limit the discretion of the CCC to make any other Document available to the Participants or the authority of the Hearing Officer to order the production of any other Documents or information by any Participant.

(b) Documents That May Be Withheld by Staff

(1) Staff may withhold a Document from inspection and copying by a Participant if:[1]

i. the Document is privileged to the CEA or constitutes attorney work product of counsel for the CEA (in applying this provision, the attorney-client privilege shall be recognized as absolute and any demand for production of attorney work product shall be granted only after a showing of substantial need by the Respondent or other Participant);

ii. the Document is an examination or inspection report, an internal memorandum, or other note or writing prepared by a Staff member that will not be offered in evidence or otherwise relied on by Staff in the hearing;

iii. the Document would disclose:

(1) an examination, investigatory or enforcement technique or guideline not otherwise made public of the CEA, a federal, state, or foreign regulatory authority, or a self-regulatory organization;

(2) the identity of a source, including a federal, state, or foreign regulatory authority or a self-regulatory organization, that furnished information or was furnished information on a confidential basis regarding an investigation, an examination, an enforcement proceeding, or any other type of civil or criminal enforcement action;

(3) or an examination, an investigation, an enforcement proceeding, or any other type of civil or criminal enforcement action under consideration by, or initiated by, the CEA, a federal, state, or foreign regulatory authority, or a self-regulatory organization; or

iv. the Hearing Officer grants leave to withhold a Document or category of Documents as not relevant to the subject matter of the proceeding, or for other good cause shown.

Provided, that where a Document contains information of the type listed in subsections (i), (ii), (iii) or (iv) that is capable of being redacted, Staff shall make the Document available for inspection and copying by the other Participants in redacted form.

(c) Withheld Document List: At the time it is required to make Documents available for inspection and copying, Staff shall also provide to the Hearing Officer, the Respondent and any other Participant to which Documents are being made available, a list of Documents withheld by Staff pursuant to those elements listed above, with a statement of the grounds that support withholding the Document. Upon review, for good cause shown, the Hearing Officer may order Staff to make any Document withheld, other than a Document that is subject to the attorney-client privilege, available to the other Participants for inspection and copying.

(d) Timing of Inspection and Copying: Except as set forth in this Section, the Hearing Officer shall determine the schedule of production of Documents for inspection and copying, provided that the Hearing Officer may modify any period for production set forth in this Section as warranted by the circumstances.

(e) Place and Time of Inspection and Copying: Documents subject to inspection and copying pursuant to this Section shall be made available to the Respondent and other Participants for inspection and copying at the CEA office where the Documents are ordinarily maintained, or at such other office as the Hearing Officer, in his or her discretion, shall designate, or as the Participants otherwise agree. A Participant shall be given access to the Documents at the CEA's offices during normal business hours. A Participant shall not be given custody

[1] Nothing in these subsections authorizes Staff to withhold a Document, or a part thereof, that contains exculpatory evidence. Nothing in these subsections requires Staff to withhold a Document from disclosure.

of the Documents or be permitted to remove the Documents from the CEA's offices, other than copies of Documents made available by the CEA for that purpose.

(f) **Copying Costs:** A Participant may obtain a photocopy of all Documents made available for inspection. A Participant shall be responsible for the cost of photocopying. Unless otherwise ordered by the Hearing Officer, charges for copies made at the request of a Participant shall be at a rate to be established by the CEA.

(g) **Failure to Make Documents Available —** Harmless Error: In the event that a Document required to be made available to a Participant pursuant to this Section is not made available by Staff, no rehearing or amended decision of a proceeding already heard or decided shall be required where the failure to make the Document available was harmless error. Should a dispute arise as to whether a rehearing or amended decision is required due to the failure of Staff to produce a Document, the burden shall be on Staff to show that such failure was harmless error. The Hearing Officer, or, upon review, the Hearing Panel shall determine whether the failure to make the Document available was harmless error.

1.5.8 Other Discovery Procedures

(a) In addition to the production of Documents by Staff for inspection and copying by Respondent and other Participants pursuant to Section 1.5.7, the Participants shall be entitled to utilize all other discovery methods provided for in Rules 402 through 409 of the FERC Rules of Practice and Procedure, 18 C.F.R. § 385.402 through 385.409, including data requests, written interrogatories and requests for production of Documents or things, depositions by oral examination, requests for inspection of Documents and other property, requests for admissions, and requests for issuance of orders to one or more Registered Entities to produce Documents for inspection and copying or at the hearing or to provide testimony by an authorized representative in deposition or at the hearing.

(b) Unless otherwise directed by the Hearing Officer or Hearing Panel upon motion by a Participant, or by the Hearing Officer, or by the Hearing Panel on its own motion, such discovery, and the resolution of any disputes concerning such discovery, shall be conducted in accordance with the provisions of Rules 402 through 410 and 510(e) of the FERC Rules of Practice and Procedure, 18 C.F.R. §§ 385.402 through 385.410 and 385.510(e), which are hereby incorporated by reference into these Hearing Procedures, subject to the following limitations and modifications to such Rules:

(1) The provisions of subsections (d), (e) and (f) of Section 1.5.7 shall apply to any such discovery.

(2) Rule 403(b)(2) (18 C.F.R. § 385.403(b)(2)) and Rule 410(d)(2) (18 C.F.R. § 385.410(d)(2)) shall not be applicable.

(3) The Hearing Officer and the Hearing Panel have the authority to issue orders to compel the appearance by or production of Documents or information by, only a Person that (i) is a Participant or (ii) is a Registered Entity (including an authorized representative thereof) that is not a Participant. The Hearing Officer and the Hearing Panel do not have authority to require a United States marshal or deputy marshal to serve an order to produce or provide Documents, information or testimony.

(4) References to "subpoena" in Rules 404, 409, 410 and 510(e) shall be deemed to be to an order to a non-Participant Registered Entity to produce or provide Documents, information or testimony.

(5) References to the "Commission" in Rules 402 through 410 and 510(e) shall be to FERC except as follows:

i. the references in Rules 402(a), 404(b)(1) and 405(b), the second reference in Rule 410(d), and the references in Rule 510(e)(1) and (2) shall be deemed to be to the Hearing Panel.

ii. the reference in Rule 385.406(b)(4) to "Commission trial staff" shall be deemed to be to Staff, and

iii. the reference in Rule 510(e)(3) shall be deemed to be to the Hearing Officer or Hearing Panel.

(6) Unless otherwise ordered by the Hearing Officer or Hearing Panel, a data request, set of interrogatories, request for production of Documents or things, request for inspection of Documents or other property, request for admissions, or order to produce or provide Documents, information or testimony, shall not specify a due date or response date that is fewer than 21 days from the date of service of the request or date of the order.

(7) A list of withheld Documents, if any, shall be provided by any Participant required to produce Documents, at the time the Documents are required to be produced, to the Hearing Officer and to each Participant entitled to receive production of the Documents. Upon review, for good cause shown, the Hearing Officer may order the Participant to make any Document withheld available to any other Participant or Participants for inspection and copying.

(8) In the event a Document or information required to be produced or provided by a Participant pursuant to discovery is not produced or provided by the Participant, no rehearing or amended decision of a proceeding already heard or decided shall be required where the failure to produce or provide the Document or information was harmless error. Should a dispute arise as to whether a rehearing or amended decision is required due to the failure of a Participant to produce or provide a Document or information, the burden shall be on the Participant that failed to produce or provide the Document or information to show that such failure was harmless error. The Hearing Officer or, upon review, the Hearing Panel shall determine whether the failure to make the Document available was harmless error.

(9) Unless otherwise ordered by the Hearing Officer or Hearing Panel, all such discovery shall be requested, scheduled and conducted so as to be completed within six (6) months following the date the request for hearing was filed.

(10) Notwithstanding subsections (b) (6) and (b) (9), however, if the shortened hearing procedure in Section 1.3.4 is used in a proceeding, the Hearing Officer, on his or her own motion or on motion of a Participant, shall establish a schedule for discovery, including response periods for responding to discovery requests, that are consistent with the expedited nature of the proceeding contemplated by the shortened hearing procedure.

(c) The Hearing Officer's ruling on all motions relating to disputes concerning such discovery shall consider the following objectives:

(1) full disclosure of all relevant Documents and information; and

(2) the exercise of due diligence in the conduct of discovery by a Participant; and disallowing use of discovery as a means to delay the proceeding or to harass or burden any other Participant.

1.5.9 Pre-Evidentiary Hearing Submission of Testimony and Evidence

(a) Unless the Hearing Officer orders otherwise and with the exception of (i) any adverse Participant examination pursuant to Section 1.6.16 and (ii) the testimony and documents of a non- Participant provided pursuant to an order to produce or provide Documents, information or testimony, all witness direct testimony to be submitted in an evidentiary hearing must be prepared in written form, may have exhibits, schedules and attachments thereto, and shall be filed in advance of the evidentiary hearing pursuant to a schedule determined by the Hearing Officer, as it may be amended. Where a Participant intends to use a Document

or other demonstrative evidence that has not been filed as part of written testimony in the conduct of cross-examination (other than Documents that are to be produced by a non-Participant at the hearing pursuant to an order to produce Documents), the Participant intending to use such Document or demonstrative evidence shall provide it to the other Participants and the Hearing Officer at least three (3) business days prior to the date at which the witness will be cross-examined at a testimonial hearing.

(b) Staff shall file the Documents it intends to offer into evidence as its direct case, including the written testimony of its witnesses along with exhibits, schedules, and attachments thereto, first. The Registered Entity shall file the Documents it intends to offer into evidence as its direct case, which also may be responsive to Staff's direct case, including the written testimony of its witnesses along with exhibits, schedules and attachments thereto, second. Staff shall file as its rebuttal case the Documents it intends to offer into evidence in response to the Registered Entity's direct case, including the written testimony of its witnesses along with exhibits, schedules, and attachments thereto, third.

(c) If appropriate due to the number and/or complexity of the issues, the Hearing Officer may allow for the Registered Entity to submit a rebuttal case that responds to Staff's rebuttal case, in which event the Hearing Officer shall also allow Staff to submit a rebuttal case that responds to the Registered Entity's rebuttal case.

(d) Each round of evidence shall be limited in scope to responding to the preceding round of evidence, except that the Registered Entity's direct case may exceed the scope of Staff's direct case if necessary for the Registered Entity to set forth its direct case fully.

(e) The Participants shall file the Documents they intend to offer into evidence in accordance with the Hearing Officer's schedule, as it may be amended. Such filings of written testimony and other evidence in advance of the evidentiary hearing shall not entitle the Documents to be admitted into the evidentiary record. The Participants must offer their witnesses' testimony and other proposed evidence for admission into the evidentiary record during the evidentiary hearing.

(f) Any Participant who fails, without good cause shown, to comply with the Hearing Officer's schedule for the filing of written testimony and other evidence in advance of the evidentiary hearing may be limited in the presentation of its evidence during the evidentiary hearing or have its participation in the evidentiary hearing otherwise restricted by the Hearing Officer to avoid undue prejudice and delay.

1.5.10 Protective Orders

(a) All proceedings conducted pursuant to these Hearing Procedures, and any written testimony, exhibits, other evidence, transcripts, comments, briefs, rulings and other issuances, shall be non-public and shall be held in confidence by all Participants, except as the ERO (within the U.S., in accordance with the authorization previously granted by FERC to release information about a non-public proceeding) or FERC (in the case of U.S. related information) or another Applicable Governmental Authority (in the case of non U.S. related information) authorizes or directs public disclosure of any portion of the record. In addition to this general proscription, at any time during a proceeding, the Hearing Officer, on his or her own motion or on the motion of any Participant or of any non-Participant ordered to produce Documents, information or testimony, may enter a protective order to designate as proprietary and protect the confidential, proprietary or trade secret nature of any data, information or studies, or any other information the public release of which may cause a security risk or harm to a Participant.

(b) The following types of information will be considered entitled to protection through a protective order:

(1) Confidential Business and Market Information, including information that is proprietary, commercially valuable, or competitively sensitive;

(2) Critical Energy Infrastructure Information;

(3) information related to a Cyber Security Incident;

(4) personnel information that identifies or could be used to identify a specific individual, or that reveals personnel, financial, medical or other personal information;

(5) audit work papers; or

(6) investigative files or Documents that would disclose investigative techniques of Staff, any CEA, the ERO or any federal, state or foreign regulatory authority.

Nothing in this subsection 1.5.10(b) shall require Staff to produce any Documents it is entitled to withhold under subsection 1.5.7(b).

(c) A motion for a protective order shall specify the proposed expiration date for the proprietary status of the data, Documents, or information, if any, and shall propose requirements or safeguards to be met for individuals participating in the proceeding to review the protected information while maintaining its proprietary status.

(d) A Document submitted and marked as proprietary, or a statement made at a hearing and identified as proprietary, shall be afforded proprietary treatment pending the timely submission of a motion to protect the confidential, proprietary or trade secret nature of that Document or statement and a ruling on such a motion by the Hearing Officer.

(e) The protective order shall identify the data, Documents, or information that will be accorded proprietary treatment; the individuals participating in the proceeding, by category or otherwise, entitled to view the proprietary information; and the requirements, conditions or safeguards that must be met before an individual may view the information.

(f) A public redacted version of each Document and transcript that contains information that is protected pursuant to this Section must be filed with the proprietary version and must be served on each Participant for distribution to those individuals participating in the proceeding who are not entitled to view the proprietary information.

(g) Should it be necessary to address proprietary information during a hearing, the Hearing Officer shall, while the information is being addressed, close the hearing to all individuals other than those entitled to view or hear the proprietary information in accordance with the protective order.

1.5.11 Pre-Evidentiary Hearing Memorandum

(a) The Hearing Officer or the Hearing Panel may request the submission of memoranda prior to the evidentiary hearing that set forth each Participant's position on the issue(s) in dispute, the key facts and arguments, the applicable Reliability Standard, rules, orders or other authority, and such other matters as may be directed by the Hearing Officer or the Hearing Panel.

(b) The purpose of such memoranda will be to aid the Hearing Officer and Hearing Panel in preparation for the evidentiary hearing. A Participant will not be deemed to have waived any issue, fact or argument that is not set forth in a pre-evidentiary hearing memorandum.

(c) The Hearing Officer may establish word limitations on such submissions.

1.5.12 Certification of Questions to the NERC Board of Trustees Compliance Committee

(a) Should a hearing present a significant question of law, policy or procedure the resolution of which may be determinative of the issues in the proceeding in whole or in part, and as to which there are other extraordinary circumstances that make prompt consideration of the question by the NERC Board of Trustees Compliance Committee appropriate, the Hearing Officer, on his or her own motion or on motion of a

Participant, may recommend to the Hearing Panel that it certify, or the Hearing Panel on its own motion may decide to certify, the question to the Board of Trustees Compliance Committee for determination pursuant to Section 412 of the Rules of Procedure.

(b) If the Hearing Officer, on his or her own motion, or the Hearing Panel, on its own motion, wishes to present a question to the Hearing Panel for certification to the NERC Board of Trustees Compliance Committee, the Hearing Officer shall first provide the Participants the opportunity to submit memoranda addressing whether the question should be certified and the precise terms of the question to be certified.

(c) If a Participant files a motion requesting, or the Hearing Officer determines on his or her own motion, that a question should be certified to the Board of Trustees Compliance Committee, the Hearing Officer shall submit a written recommendation on the matter to the Hearing Panel. If the request for certification is based on the motion of a Participant, the Hearing Officer shall also submit to the Hearing Panel the motion and any answers to the motion that were filed. If the request for certification is on the Hearing Officer's own motion, the Hearing Officer shall also submit to the Hearing Panel the Participants' memoranda that were filed pursuant to subsection (b).

(d) Questions of fact presented by the particular matter in dispute in a hearing shall not be the subject of a certification to the Board of Trustees Compliance Committee.

(e) The Hearing Panel shall determine, based on the criteria specified in subsection (a), whether the proposed question shall be certified to the Board of Trustees Compliance Committee for determination. To certify the proposed question, the Hearing Panel must determine that the question is a significant question of law, policy or procedure the resolution of which may be determinative of the issues in the proceeding, in whole or in part, and that there are extraordinary circumstances that make prompt consideration of the question by the Board of Trustees Compliance Committee appropriate. If the Hearing Panel determines that the proposed question should be certified to the Board of Trustees Compliance Committee, the Hearing Panel shall also determine whether the hearing should be suspended, in whole or in part, while the question is pending before the Board of Trustees for determination.

(f) As provided in Rule of Procedure Section 412, the Board of Trustees Compliance Committee may decide to reject a proposed certification from a Hearing Panel.

(g) If the Board of Trustees Compliance Committee accepts certification of a question and issues a determination on the question, the hearing shall proceed following the determination in accordance with the Board of Trustees Compliance Committee's decision.

1.6 Procedure at Evidentiary Hearing

1.6.1 Purpose of Evidentiary Hearing

The purpose of the evidentiary hearing shall be to admit the Participants' evidence into the record, and for each Participant to have the opportunity to cross-examine the other Participant's witnesses. A schedule for briefs, unless waived by the Participants, shall be set at the conclusion of the evidentiary hearing.

1.6.2 Order of Receiving Evidence

In all proceedings Staff shall open and close.

1.6.3 Opening and Closing Statements

Opening and closing statements will not be made during the evidentiary hearing as a matter of course except that such statements may be allowed when requested by a Participant, and shall be required when requested by the Hearing Officer or the Hearing Panel. Any Participant's request for such statements, or a Hearing Officer or Hearing Panel notice requiring such statements, shall be made at least ten (10) days in advance of the start of the evidentiary hearing.

1.6.4 Right of Participant to Present Evidence

Subject to compliance with the requirements of these Hearing Procedures concerning the timing of submission of written testimony and other evidence, a Participant has the right to present such evidence, to make such objections and arguments, and to conduct such cross-examination as may be necessary to assure the true and full disclosure of the facts.

1.6.5 Exhibits

(a) All material offered in evidence, except oral testimony allowed by the Hearing Officer or the testimony of a non-Participant pursuant to an order to produce or provide Documents, information or testimony, shall be offered in the form of an exhibit.

(b) Each exhibit must be marked for identification. A Participant must provide the court reporter with two (2) copies of every exhibit that the Participant offers into evidence, and will provide copies of any exhibit not served in advance of the evidentiary hearing to the Participants and the Hearing Officer.

1.6.6 Witness Attendance at Testimonial Hearing

(a) Each witness shall attend the testimonial hearing in person unless a Participant has been informed in advance of the testimonial hearing that all other Participants waive cross- examination of the witness and neither the Hearing Officer nor the members of the Hearing Panel have any questions for the witness, in which event the witness does need not be present at the testimonial hearing.

(b) A person compelled to appear, voluntarily testifying, or making a statement may be accompanied, represented, and advised by an attorney.

(c) All testimony offered at a testimonial hearing is to be under oath or affirmation. If a witness is not required to attend the testimonial hearing, then the Participant on whose behalf the witness prepared testimony shall submit an affidavit of the witness attesting to the veracity of the witness' testimony, and the Participant shall be allowed to introduce the witness' testimony, and the exhibits, schedules and attachments thereto, into the evidentiary record based on such affidavit.

1.6.7 Admission of Evidence

(a) Staff shall offer its exhibits into evidence first and the Registered Entity second, unless the Participants agree otherwise.

(b) Except for witnesses who are not required to attend the testimonial hearing, the Participants shall call each witness in turn. Following the witness' swearing in, the witness shall attest to the veracity of his or her written testimony. The witness may identify any language and/or figures in his or her written testimony or exhibits that the witness would like to change or correct. Subject to objection, such changes or corrections may be allowed at the Hearing Officer's discretion for the purpose of obtaining a full, accurate, and complete record without imposing undue delay or prejudice on any Participant. The Participant whose witness has made changes or written corrections to written testimony and exhibits shall file corrected copies with the Clerk and provide corrected copies to the Hearing Officer and other Participant.

(c) Once a witness has attested to the veracity of his or her testimony, the Participant on whose behalf the witness is testifying shall move for admission of the witness' testimony, including all exhibits, schedules, and attachments thereto, into evidence. Other Participants may object to the introduction of the witness' testimony, or any part thereof, as set forth in Section 1.6.11. Subject to the Hearing Officer's ruling on the objection, the witness' testimony shall be admitted into evidence. The witness shall then be turned over for cross-examination by other Participants, and for any questions by the Hearing Officer or any member of the Hearing Panel, in accordance with Section 1.6.14, and then for redirect examination in accordance with Section 1.6.15. Witnesses shall be cross-examined on all previously-served testimony (direct, rebuttal or surrebuttal) when they first take the witness stand.

(d) Except (i) in exceptional cases and upon a showing of good cause and (ii) witnesses testifying pursuant to an order to produce or provide Documents, information or testimony issued to a non-Participant, no witness shall be allowed to testify unless a Participant has served the witness' written testimony in advance of the testimonial hearing in accordance with the schedule established by the Hearing Officer. Due to the undue prejudice such surprise witness testimony would impose on other Participants, it is the CCC's policy to discourage witness testimony at a testimonial hearing when a Participant has not served the witness' written testimony in advance of the testimonial hearing. If such testimony is allowed, sufficient procedural steps shall be taken by the Hearing Officer to provide the other Participants with a fair opportunity for response and cross-examination.

1.6.8 Evidence that is Part of a Book, Paper or Document

(a) When relevant and material matter offered in evidence is embraced in a book, paper or Document containing other matter that is not material or relevant, the Participant offering the same must plainly designate the matter offered as evidence, and segregate and exclude the material not offered to the extent practicable.

(b) If the material not offered is in such volume as would unnecessarily encumber the record, such book, papers or Document will not be received in evidence but may be marked for identification and, if properly authenticated, the relevant or material matter may be read into the record, or, if the Hearing Officer so directs, a separate copy of such matter in proper form shall be offered as an exhibit.

(c) All other Participants shall be afforded an opportunity to examine the book, paper, or Document and to offer in evidence in like manner other portions thereof if found to be material and relevant.

1.6.9 Stipulations

The Participants may stipulate to any relevant fact or the authenticity of any relevant Document. Stipulations may be made in writing or entered orally in the record. Notwithstanding stipulation, the Hearing Officer may require evidence of the facts stipulated in order to provide a complete evidentiary record on which to base the final order.

1.6.10 Official Notice

(a) Where relevant and material to the subject matter of the proceeding, the Hearing Officer may, upon request of a Participant, take official notice of any of the following:

(1) Rules, regulations, administrative rulings, and orders, written policies of governmental bodies, and rulings and orders of other CEAs.

(2) The orders, transcripts, exhibits, pleadings, or any other matter contained in the record of other docketed proceedings of the CEA.

(3) State, provincial and federal statutes and municipal and local ordinances.

(4) The decisions of state, provincial, and federal courts.

(5) Generally recognized scientific or technical facts within the specialized knowledge of the CEA.

(6) All other matters of which the courts of the United States may take judicial notice.

(b) All requests to take official notice shall be submitted in advance of the evidentiary hearing in accordance with a schedule established by the Hearing Officer. Before ruling on a request to take official notice, the Hearing Officer shall afford the other Participant opportunity to object or to show the contrary to the matter for which official notice is requested.

(c) An accurate copy of any item officially noticed shall be introduced into the record in the form of an exhibit presented by the Participant requesting official notice unless waived by the Participants and approved by the Hearing Officer. Any information officially noticed and not presented as an exhibit shall be set forth in a statement on the record.

1.6.11 Admissibility of Evidence

(a) Any evidence offered, including that included in a book, paper, or Document pursuant to Section 1.6.8, shall be subject to appropriate and timely objections. Any Participant objecting to the admission or exclusion of evidence must state the grounds for objection.

(b) The admission of evidence shall not be limited by the generally recognized rules of evidence as applied in the courts of the United States or of the states, although the Hearing Officer may take such rules of evidence into consideration in ruling on the admissibility of evidence. The Hearing Officer will exercise discretion in the admission of evidence based upon arguments advanced by the Participants, and shall admit evidence if it is of a type commonly relied upon by reasonably prudent persons in the conduct of their affairs. The Hearing Officer may only exclude material from the record in response to a motion or objection by a Participant.

(c) Formal exception to a ruling on admissibility of evidence need not be taken to be preserved.

1.6.12 Offer of Proof

Any Participant who has had evidence excluded may make an offer of proof on the record. The offer of proof may consist of a statement made on the record of the substance of the evidence that the Participant claims would have been adduced, or any written or documentary exhibit that the Participant sought to introduce. Any such exhibit shall be retained as part of the record.

1.6.13 Reservation of Evidentiary Ruling

(a) The Hearing Officer shall rule upon any objection to the admissibility of evidence at the time the objection is made; provided that the Hearing Officer has discretion to reserve such a ruling or to require the Participants to file written arguments in relation thereto.

(b) If the Hearing Officer reserves the ruling, appropriate steps shall be taken during the evidentiary hearing to ensure a full, complete, and accurate record in relation to the objected to evidence in the event the objection to the evidence's admissibility is overruled.

1.6.14 Cross-Examination

(a) Each witness shall be tendered for cross-examination subsequent to the admission of the witness' testimony into the evidentiary record. Each Participant shall have the right to cross-examine each witness of any other Participants. A Participant may waive cross-examination of any witness. Leading questions are permitted on cross-examination.

(b) The credibility of a witness may be attacked by any Participant, including the Participant calling the witness.

(c) The Hearing Officer and any member of the Hearing Panel may ask the witness questions following the conclusion of the witness' cross-examination by the other Participant, and prior to the witness' redirect examination pursuant to Section 1.6.15.

1.6.15 Redirect Examination

A Participant shall be entitled to conduct redirect examination of each of the Participant's witnesses who are subject to cross-examination or questions of the Hearing Officer or a member of the Hearing Panel. Any redirect examination shall be limited in scope to the witness' cross- examination and questions of the Hearing Officer and members of the Hearing Panel.

1.6.16 Examination of Adverse Participant

(a) Any Participant may call any adverse Participant, or any employee or agent thereof, during the testimonial hearing to provide oral testimony on the Participant's behalf, and may conduct such oral examination as though the witness were under cross-examination.

(b) If a Participant intends to call an adverse Participant for examination, it shall give notice to the Hearing Officer and all other Participants setting forth the grounds for such examination at least fourteen (14) days in advance of the testimonial hearing, and the Participant who, or whose employee or agent, is sought to be called shall file any objection at least seven (7) days in advance of the testimonial hearing

(c) Any Participant may conduct oral examination of a witness testifying pursuant to an order to produce or provide Documents, information or testimony issued to a non-Participant, as though the witness were under cross-examination.

1.6.17 Close of the Evidentiary Record

(a) The Hearing Officer shall designate the time at which the evidentiary record will be closed, which will typically be at the conclusion of the evidentiary hearing.

(b) Evidence may not be added to the evidentiary record after it is closed, provided that, prior to issuance of the Hearing Panel's final order, the Hearing Officer may reopen the evidentiary record for good cause shown by any Participant. For the purpose of reopening the evidentiary record, newly discovered evidence that is material to the issues in dispute and could not, by due diligence, have been discovered prior to or during the evidentiary hearing, shall constitute good cause.

1.7 Post Evidentiary Hearing Procedure

1.7.1 Briefs

(a) At the close of the evidentiary hearing, Participants may file initial and reply briefs.

(b) Briefs shall be concise, and, if in excess of twenty (20) pages, excluding appendices, shall contain a table of contents. Statements of fact should be supported by record citations.

(c) The Hearing Officer will prescribe the time for filing briefs, giving due regard to the nature of the proceeding, the extent of the record, the number and complexity of the issues, and the objective of expedition.

(d) Unless the Hearing Officer prescribes otherwise, all Participants shall file initial and reply briefs simultaneously.

(e) Participants' reply briefs shall be limited in scope to responding to arguments and issues raised in other Participants' initial briefs.

(f) The Hearing Officer may allow oral closing statements to be made on the record in lieu of briefs.

(g) The Hearing Officer may establish reasonable word limitations applicable to briefs.

1.7.2 Other Pleadings

Post-hearing pleadings other than briefs are permitted, but, absent good cause shown, such pleadings may not seek to introduce additional evidence into the record.

1.7.3 Draft Initial Opinions

The Hearing Officer may permit or require Participants to file draft initial opinions that set forth the Participants' proposed findings of fact and conclusions.

1.7.4 Hearing Officer's Initial Opinion

(a) At the conclusion of the evidentiary hearing, and following the submission of initial and reply briefs and draft orders, if any, the Hearing Officer shall prepare an initial opinion for the Hearing Panel's review and consideration.

(b) The initial opinion shall include a statement of each finding and conclusion, and the reasons or basis therefore, for all material issues presented on the record. The initial opinion also shall contain the appropriate orders to dispose of the proceeding, including any Penalty, Mitigation Plan or Mitigating Activities, or Remedial Action Directive that the Hearing Officer proposes the Hearing Panel require.

(c) The initial opinion shall note if the subject of the proceeding has been deemed to involve a Cyber Security Incident, if any information in the proceeding was deemed to be Critical Energy Infrastructure Information, or if any information in the proceeding is the subject of a protective order pursuant to Section 1.5.10.

1.7.5 Exceptions

(a) Within twenty-one (21) days after service of the initial opinion, or such other time as is fixed by the Hearing Officer, any Participant may file exceptions to the initial opinion in a brief designated "brief on exceptions" and, within fourteen (14) days after the time for filing briefs on exceptions or such other time as is set by the Hearing Officer, any Participant may file as a reply, a "brief in reply to exceptions."

(b) Exceptions and replies thereto with respect to statements, findings of fact or conclusion in the initial opinion must be specific and must be stated and numbered separately in the brief. With regard to each exception,

the Participant must specify each error asserted, and include a concise discussion of any policy considerations applicable and any other evidence and arguments in support of the Participant's position. Suggested replacement language for all statements to which exception is taken must be provided. Exceptions and arguments may be filed (1) together in one brief; or (2) in two separate documents, one designated as the brief containing arguments, and the other designated "Exceptions," containing the suggested replacement language.

(c) Arguments in briefs on exceptions and replies thereto shall be concise and, if in excess of twenty (20) pages, shall contain a table of contents.

(d) Participants shall not raise arguments in their briefs in reply to exceptions that are not responsive to any argument raised in any other Participant's brief on exceptions.

(e) Statements of fact should be supported by citation to the record.

(f) The Hearing Officer may establish reasonable word limitations applicable to arguments included in briefs on exception and briefs in reply to exceptions. Such word limitations shall not apply to a Participant's proposed replacement language.

(g) Unless good cause is shown, if a Participant does not file a brief on exceptions, or if a Participant filed a brief on exceptions that does not object to a part of the initial opinion, the Participant shall be deemed to have waived any objection to the initial opinion in its entirety, or to the part of the initial opinion to which the Participant did not object, whichever applies. This provision shall not prohibit the Participant, in its brief in reply to exceptions, from responding to another Participant's exceptions to such part of the initial opinion or from proposing alternative replacement language to the replacement language proposed by the other Participant for such part of the initial opinion.

1.7.6 Oral Argument

(a) The Hearing Panel may elect to hear oral argument. If oral argument is held without briefs having been filed, Participants will be given the opportunity to present argument on all issues.

(b) If oral argument is held where briefs have been filed, argument may be limited to issues identified by the Hearing Panel. The Hearing Panel will direct the Clerk to issue a notice of oral argument that identifies the date, time, place and issues for the argument.

(c) The presentation of written materials or visual aids is permitted at oral argument. To the extent such materials or aids contain factual information, they shall be supported by the record, and contain accurate citations to the record. Such materials or aids may not contain new calculations or quantitative analyses not presented in the record, unless they are based on underlying data contained in the record. Copies of all written materials or visual aids to be presented at oral argument shall be served on all Participants not less than forty-eight (48) hours prior to the time and date of oral argument.

1.7.7 Additional Hearings

After the evidentiary record has been closed but before issuance of the Hearing Panel's final order, the Hearing Officer may reopen the evidentiary record and hold additional hearings. Such action may be taken on the Hearing Officer's or the Hearing Panel's own motion if there is reason to believe that reopening is warranted by any changes in conditions, or by the need to compile a complete evidentiary record on which to base the final order. Any Participant may file a motion to reopen the record, which shall contain the reasons for reopening, including material changes in conditions or the identification of additional evidence that should be included in the record, and a brief statement of proposed additional evidence and an explanation why such evidence was not previously cited as evidence.

1.7.8 Hearing Panel Final Order

(a) Following the receipt of the initial opinion, any exceptions, and replies thereto, and oral argument, if any, the Hearing Panel shall issue its final order.

(b) Issuance of a final order shall require (i) a quorum of the Hearing Panel, which shall be (after any recusals, disqualifications and appointments of replacement members) at least fifty (50) percent of the number of members normally assigned to the Hearing Panel, and (ii) majority vote of the members of the Hearing Panel voting on the final order (in which the number of members voting shall not be less than a quorum).

(c) The Hearing Panel shall issue its final order within thirty (30) days following the last to occur of the initial opinion, exceptions, replies thereto, or oral argument. The Hearing Panel may extend this deadline for good cause and shall provide written notice of any extension to all Participants. The final order may adopt, modify, amend, or reject the initial opinion in its entirety or in part. The final order shall include a statement of each finding and conclusion, and the reasons or basis therefore, for all material issues presented on the record.

(d) The Hearing Panel will base its determinations in the final order on the record. The final order also shall contain the appropriate orders to dispose of the proceeding, including any Penalty, Remedial Action Directive, Mitigation Plan or Mitigating Activities required.

(e) The final order shall note if the subject of the proceeding has been deemed to involve a Cyber Security Incident, if any information in the proceeding was deemed to be Critical Energy Infrastructure Information, or if any information in the proceeding is the subject of a protective order issued pursuant to Section 1.5.10.

(f) The service of the final order shall include a notice informing the Participants of their appeal rights to the ERO or to FERC, as applicable.

1.7.9 The Record

(a) The Clerk shall maintain the record for all dockets. The record shall include any of the following, including all attachments thereto and Documents filed therewith, that exist in any docket:

(1) Notice of Alleged Violation and Registered Entity's response thereto;

(2) Registered Entity's proposed Mitigation Plan or Mitigating Activities and Staff's statement identifying its disagreement(s) therewith;

(3) Remedial Action Directives and the Registered Entity's notice contesting the Remedial Action Directive;

(4) Registered Entity's request for a hearing;

(5) Participant filings, motions, and responses;

(6) Notices, rulings, orders and other issuances of the Hearing Officer and Hearing Panel;

(7) Transcripts;

(8) Evidence received;

(9) Written comments submitted in lieu of written testimony;

(10) Matters officially noticed;

(11) Offers of proof, objections and rulings thereon, and any written or documentary evidence excluded from the evidentiary record;

(12) Pre-evidentiary hearing memorandums, briefs, and draft opinions;

(13) Post-hearing pleadings other than briefs;

(14) The Hearing Officer's initial opinion;

(15) Exceptions to the Hearing Officer's initial opinion, and any replies thereto;

(16) The Hearing Panel's final order and the Clerk's notice transmitting the final order to the Participants;

(17) All notices of ex parte communications; and

(18) Any notifications of recusal and motions for disqualification of a member of the Hearing Panel or Hearing Officer or Technical Advisor and any responses or replies thereto.

1.7.10 Appeal

A Participant or a Regional Entity acting as the CEA, may appeal a final order of the Hearing Panel to NERC in accordance with Rules of Procedure Section 409.

1.8 Settlement

Settlements may be entered into at any time pursuant to Section 5.6 of the NERC Compliance Monitoring and Enforcement Program and the CEA's settlement procedures, provided, that (i) the CEA may decline to engage in or continue settlement negotiations after a Possible Violation or Alleged Violation becomes a Confirmed Violation, and (ii) the CEA, the Registered Entity or any other Participant may terminate settlement negotiations at any time.

1.9 Remedial Action Directives

1.9.1 Initiation of Remedial Action Directive Hearing

(a) Staff may issue a Remedial Action Directive to a Registered Entity at any time, including during any proceeding related to an Alleged Violation of a Reliability Standard. The Remedial Action Directive shall be delivered to the Registered Entity in accordance with Section 7.0 of the NERC Compliance Monitoring and Enforcement Program.

(b) The Registered Entity may contest the Remedial Action Directive by filing a written notice with the NERC Director of Enforcement that states that the Registered Entity contests the Remedial Action Directive and that the Registered Entity requests a Remedial Action Directive hearing. The Registered Entity shall attach a copy of the Remedial Action Directive to its written notice. The Registered Entity must provide such notice within two (2) business days following the date of actual receipt (as defined in Section 7.0 of the NERC Compliance Monitoring and Enforcement Program) of the Remedial Action Directive. If the Registered Entity does not give written notice within the required period, the Registered Entity shall be deemed to have waived its right to contest the Remedial Action Directive.

(c) The Clerk shall assign a docket number, and issue a notice of hearing that sets forth the date, time, and place at which the hearing will convene.

1.9.2 Remedial Action Directive Hearing Procedure

(a) Hearings to address Remedial Action Directives shall be conducted only under the expedited hearing process set forth in this Section. The general hearing procedures described in Sections 1.4 to 1.7 are applicable to the Remedial Action Directive hearing unless the context of a provision is inconsistent with or otherwise renders it inapplicable to the procedures set forth in this Section.

(b) The Remedial Action Directive hearing shall be presided over by a Hearing Officer and will be conducted according to the following guidelines:

(1) The Hearing Officer or the Hearing Panel will hold a prehearing conference within two (2) business days after receipt of the Registered Entity's request for a hearing.

(2) A testimonial hearing will be conducted on the matter, in person or by teleconference, within seven (7) business days after the prehearing conference.

(3) At the testimonial hearing, Staff shall present oral witness testimony and evidence to show why the Remedial Action Directive should be complied with, and the Registered Entity shall present oral witness testimony and evidence to show why the Remedial Action Directive is not necessary or should be modified. All witness testimony shall be rendered under oath.

(4) At the testimonial hearing, the Participants shall have the opportunity to make opening statements. In addition, the Participants shall have the opportunity to make closing arguments, and Staff shall have the opportunity to make a rebuttal to the Registered Entity's closing argument.

(5) The Participants may file initial briefs and reply briefs, and/or draft opinions, on an expedited schedule set by the Hearing Officer or the Hearing Panel. Oral argument shall not be held.

(c) The Hearing Panel shall issue a summary written decision within ten (10) days following submission of the last brief, stating whether the Registered Entity shall or shall not be required to comply with the Remedial Action Directive and identifying any modifications to the Remedial Action Directive that the Hearing Panel finds appropriate. Upon issuance of the summary written decision, the Registered Entity is required to comply with the Remedial Action Directive as specified in the summary written decision.

(d) Within thirty (30) days following issuance of its summary written decision, the Hearing Panel shall issue a full written decision. The written decision shall state the conclusions of the Hearing Panel with respect to the Remedial Action Directive, and shall explain the reasons for the Hearing Panel's conclusions.

CCCPP-004-2 Hearing Procedures – Redline

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

~~NERC Compliance and Certification Committee~~

~~Hearing Procedures~~

~~CCC Monitoring Program — CCCPP–004–1~~

to ensure the reliability of the bulk power system

~~Version 1.0~~

116-390 Village Blvd., Princeton, NJ 08540
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NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Compliance and Certification Committee Hearing Procedures

CCCPP-004-~~1~~2

Effective: ~~June 10, 2010~~[proposed date], Version ~~1~~2.0

to ensure the reliability of the bulk power system

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Table of Contents

Preface vi

Hearing Procedures 1

1.1 Applicability, Definitions and Interpretation 1

1.1.1 Procedure Governed 1

1.1.2 Deviation 1

1.1.3 Standards for Discretion 2

1.1.4 Interpretation 2

1.1.5 Definitions 2

1.2 General Provisions including Filing, Service, Transcription and Participation 4

1.2.1 Contents of Filings 4

1.2.2 Form of Filings 5

1.2.3 Submission of Documents 5

1.2.4 Service 6

1.2.5 Computation of Time 7

1.2.6 Extensions of Time 7

1.2.7 Amendments 7

1.2.8 Transcripts 7

1.2.9 Rulings, Notices, Orders and Other Issuances 7

1.2.10 Location of Hearings and Conferences 8

1.2.11 Participant Participation 8

1.2.12 Interventions 8

1.2.13 Proceedings Closed to the Public 9

1.2.14 Docketing System 9

1.2.15 Representations Deemed to be made in All Pleadings 10

1.2.16 Hold Harmless 10

1.3 Initiation of the Hearing Process 11

1.3.1 Registered Entity's Option to Request a Hearing 11

1.3.2 Staff's Response to Request for Hearing 12

1.3.3 Notice of Hearing 13

1.3.4 Shortened Hearing Procedure 13

1.4 General Hearing Procedure 15

1.4.1 [Intentionally Left Blank] 15

1.4.2 Hearing Officer 15

1.4.3 Hearing Panel 16
1.4.4 Interlocutory Review 17
1.4.5 Disqualification 18
1.4.6 Technical Advisor 18
1.4.7 No Ex Parte Communications 19
1.4.8 Appearances 19
1.4.9 Failure to Appear or Exercise Diligence 20
1.4.10 Consolidation of Proceedings 20
1.5 Prehearing Procedure 0
1.5.1 [Intentionally Left Blank] 0
1.5.2 Prehearing Conference 0
1.5.3 Summary Disposition 0
1.5.4 Status Hearings 1
1.5.5 Motions and Responses 1
1.5.6 Experts 2
1.5.7 Inspection and Copying of Documents in Possession of Staff 2
1.5.8 Other Discovery Procedures 4
1.5.9 Pre-Evidentiary Hearing Submission of Testimony and Evidence 6
1.5.10 Protective Orders 7
1.5.11 Pre-Evidentiary Hearing Memorandum 8
1.5.12 Certification of Questions to the NERC Board of Trustees Compliance Committee 8
1.6 Procedure at Evidentiary Hearing 10
1.6.1 Purpose of Evidentiary Hearing 10
1.6.2 Order of Receiving Evidence 10
1.6.3 Opening and Closing Statements 10
1.6.4 Right of Participant to Present Evidence 10
1.6.5 Exhibits 10
1.6.6 Witness Attendance at Testimonial Hearing 10
1.6.7 Admission of Evidence 11
1.6.8 Evidence that is Part of a Book, Paper or Document 11
1.6.9 Stipulations 12
1.6.10 Official Notice 12
1.6.11 Admissibility of Evidence 12
1.6.12 Offer of Proof 12
1.6.13 Reservation of Evidentiary Ruling 13

1.6.14 Cross-Examination 13
1.6.15 Redirect Examination 13
1.6.16 Examination of Adverse Participant 13
1.6.17 Close of the Evidentiary Record 14
1.7 Post Evidentiary Hearing Procedure 15
1.7.1 Briefs 15
1.7.2 Other Pleadings 15
1.7.3 Draft Initial Opinions 15
1.7.4 Hearing Officer's Initial Opinion 15
1.7.5 Exceptions 16
1.7.6 Oral Argument 16
1.7.7 Additional Hearings 17
1.7.8 Hearing Panel Final Order 17
1.7.9 The Record 17
1.7.10 Appeal 18
1.8 Settlement 19
1.9 Remedial Action Directives 20
1.9.1 Initiation of Remedial Action Directive Hearing 20
1.9.2 Remedial Action Directive Hearing Procedure 20

NERC Compliance and Certification Committee		CCCPP-004-~~1~~2
Title: Hearing Procedures		
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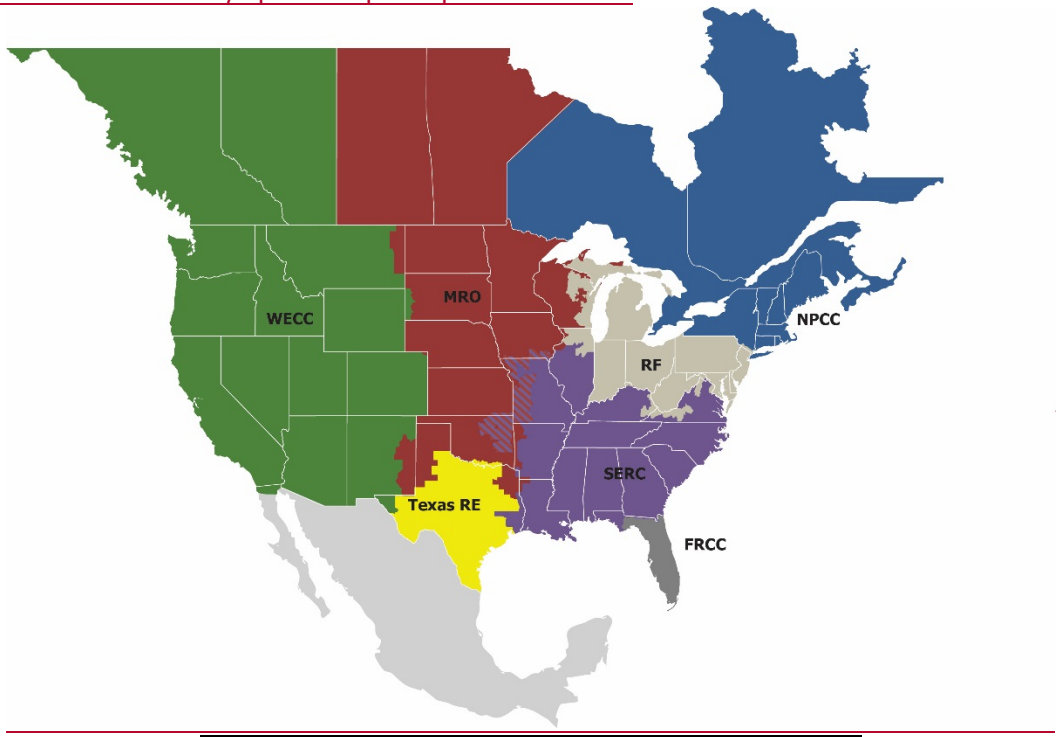
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Preface

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~~ Regional Entity 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

Hearing Procedures

1.1 Applicability, Definitions and Interpretation

~~Summary~~

1.1.1 Procedure Governed

The provisions set forth in this ~~document~~Attachment ("Hearing Procedures") shall apply to and govern practice and procedure before the Compliance and Certification Committee (~~the "~~CCC~~")~~) in hearings in the United States ~~as~~, provided, that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions, as described in the ~~North America Electric Reliability Corporation ("NERC") Rules of Procedure ("~~NERC ROP~~").~~ Section 404. Specifically, as directed by the NERC Board of Trustees, the CCC serves as the hearing body for any contest regarding findings of ~~or Penalties~~penalties or sanctions for violation(s) of Reliability Standard(s) where NERC is acting as the Compliance Enforcement Authority (CEA) and is directly monitoring the Registered Entity for compliance with those Reliability Standards (Registered Entity by agreement with a~~n~~ Regional Entity or absent a delegation agreement; the Regional Entity itself where approved Reliability Standards are applicable to the Regional Entity~~) as described in the ROP Section 409.)~~.

~~Revision History~~

~~Date~~	~~Version Number~~	~~Comments~~
~~03/03/09~~	~~1.0~~	~~Approved by CCC~~
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Table of Contents

1.Compliance and Certification Committee Hearing Procedures 1

1.1Applicability, Definitions and Interpretation 1

1.2General Provisions including Filing, Service, Transcription and Participation 4

1.3Initiation of the Hearing Process 9

1.4General Hearing Procedure 12

1.5 ..... Prehearing Procedure 18

1.6Evidentiary Hearing Procedure 26

1.7Post-Evidentiary Hearing Procedure 30

1.8 ..... Settlement 33

1.9Remedial Action Directives 34

~~Compliance and Certification Committee Hearing Procedures~~

~~1.1 Applicability, Definitions and Interpretation~~

~~1.1.1 Procedure Governed~~

The ~~provisions set forth in this document ("Hearing Procedures") shall apply to and govern practice and procedure before the Compliance and Certification Committee (the "CCC") in hearings as described in the North American Electric Reliability Corporation ("NERC") Rules of Procedure ("ROP"). Specifically, as directed by the NERC Board of Trustees, CCC serves as the hearing body for any contest regarding findings of or Penalties or sanctions for violation(s) of Reliability Standard(s) where NERC is directly monitoring the Registered Entity for compliance with those Reliability Standards (Registered Entity by agreement with an Regional Entity or absent a delegation agreement; the Regional Entity itself where approved Reliability Standards are applicable to the Regional Entity) as described in the ROP Section 409.~~

CCC shall determine: (i) whether such Registered Entities ~~as described above or whether Regional Entities~~ have violated Reliability Standards, and if so, the appropriate Mitigation ~~Plans~~Plan or Mitigating Activities as well as any ~~remedial actions~~Remedial Action Directives, Penalties and/or sanctions in accordance with the NERC ~~*ERO*~~ *Sanction Guidelines* and other applicable Penalty guidelines approved by FERC pursuant to 18 C.F.R. ~~Section~~§ 39.7(g)(2~~),~~); or (ii) a challenge by a Regional Entity regarding a Regional Entity ~~compliance program audit~~Compliance Audit finding by NERC ~~(in either case, such Respondent or Regional Entity, hereafter a "Respondent").~~ .

Any hearing conducted pursuant to these Hearing Procedures shall be conducted before a Hearing Officer and a Hearing Panel established by the CCC ~~in accordance with Section 8.3 of the CCC Charter. The~~. Where the Hearing Panel is comprised, in whole or in part, of industry stakeholders, the composition of the Hearing Panel, after any recusals or disqualifications, shall be such that no two industry ~~segments~~sectors may control, and no single industry ~~segment~~sector may veto, any decision by the Hearing Panel on any matter brought before it for decision. Where the Hearing Panel is comprised solely of independent members and an independent Hearing Officer, decisions shall require a majority vote.

The standard of proof in any proceeding under these Hearing Procedures shall be by a preponderance of the evidence. The burden of persuasion on the merits of the proceedings shall rest upon the ~~Compliance~~ Staff alleging noncompliance with a Reliability Standard, proposing a Penalty, opposing a Registered Entity's Mitigation Plan or Mitigating Activities, or requiring compliance with a Remedial Action Directive.

If a final order has been entered by the Hearing Panel, or the Hearing Panel has issued a ruling determining that there are no issues to be decided regarding the Alleged Violation, proposed Penalty amount, proposed Mitigation Plan or Mitigating Activities, or proposed Remedial Action Directive, or the Registered Entity and the CEA have entered into a settlement agreement resolving the matters that are the subject of the hearing, the hearing shall be terminated by the Hearing Panel and no further proceedings shall be conducted before the Hearing Panel.

1.1.2 Deviation

To the extent permitted by law, any provision in these Hearing Procedures may be waived, suspended, or modified by the Hearing Officer~~, as defined in Paragraph 1.1.5,~~ or the Hearing Panel, for good cause shown, either upon the Hearing Officer's or the Hearing Panel's own motion or upon the motion of any Participant.

1.1.3 Standards for Discretion

The CCC's discretion under these Hearing Procedures shall be exercised to accomplish the following goals:

(a) ~~a)~~ Integrity of the Fact-Finding Process ~~—~~- The principal goal of the hearing process is to assemble a complete factual record to serve as a basis for a correct and legally sustainable ruling, decision, or order.

(b) ~~b)~~ Fairness ~~—~~- Persons appearing in CCC proceedings should be treated fairly. To this end, Participants should be given fair notice and opportunity to present explanations, factual information, documentation, and legal argument. Action shall be taken as necessary to eliminate any disadvantage or prejudice to a Participant that would otherwise result from another Participant's failure to act diligently and in good faith.

(c) ~~c)~~ Independence ~~—~~- The hearing process should be tailored to protect against undue influence from any Person, Participant, or interest group.

(d) ~~d)~~ Balanced Decision-Making ~~—~~- Decisions should be based solely on the facts and arguments of record in a proceeding and by individuals who satisfy ~~the~~ NERC's conflict of interest policy.

(e) ~~e)~~ Impartiality ~~—~~- Persons appearing before the Hearing Panel should not be subject to discriminatory or preferential treatment. ~~Respondents~~Registered Entities should be treated consistently unless a reasonable basis is shown in any particular proceeding to depart from prior rulings, decisions, or orders.

(f) ~~f)~~ Expedition ~~—~~- Proceedings shall be brought to a conclusion as swiftly as is possible in keeping with the other goals of the hearing process.

1.1.4 Interpretation

(a) ~~a)~~ These Hearing Procedures shall be interpreted in such a manner as will aid in effectuating the Standards for Discretion set forth in ~~Paragraph~~Section 1.1.3, and so as to require that all practices in connection with the hearings shall be just and reasonable.

(b) ~~b)~~ Unless the context otherwise requires, the singular of a term used herein shall include the plural and the plural of a term shall include the singular.

(c) ~~c)~~ To the extent that the text of a rule is inconsistent with its caption, the text of the rule shall control.

1.1.5 Definitions

~~Capitalized terms~~ Unless otherwise defined below, capitalized terms used ~~used~~ in these Hearing Procedures ~~shall~~ have the ~~definitions~~ meanings set forth ~~set forth~~ in Appendix 2 of the NERC Rules of Procedure~~.~~. ~~For convenience of reference, definitions of the following terms that are used in these Hearing Procedures are also set forth below:~~

~~"Bulk Power System," for the purposes of these Hearing Procedures, means Bulk Electric System.~~

""Clerk" shall mean an individual assigned by the CCC to perform administrative tasks relating to the conduct of hearings as described in these Hearing Procedures.

"Compliance Enforcement Authority" or (CEA) means NERC in its respective role of monitoring and enforcing compliance with the NERC Reliability Standards.

~~Critical Energy Infrastructure Information" means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that: (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.~~

~~"Critical Infrastructure" means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.~~

~~"Cyber Security Incident" means any malicious or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communications networks including hardware, software and data that are essential to the Reliable Operation of the Bulk Power System.~~
"Days", as used within these Hearing Procedures, means calendar days.

"Director of ~~Compliance~~Enforcement" means the Director of ~~Compliance~~Enforcement of ~~NERC~~the CEA, as applicable, or other individual designated by the CEA, who is responsible for the management and supervision of ~~the Compliance~~Enforcement Staff, or his or her designee.

~~"Document" means, in addition to the commonly understood meaning of the term as information written or printed on paper, any electronically stored information, including writings, drawings, graphs, charts, photographs, sound recordings, images and other data or data compilations stored in any medium from which information can be obtained, and shall be translated by the producing party into reasonably usable form.~~

~~"Electric Reliability Organization" or "ERO" means the organization that is certified by the Commission under Section 39.3 of its regulations, the purpose of which is to establish and enforce Reliability Standards for the Bulk Power System of the United States, subject to Commission review.~~
~~"FERC" means the United States Federal Energy Regulatory Commission.~~

~~"Hearing Officer" means (1) a CCC member or (2) an individual employed or contracted by NERC, as designated by the CCC to preside over hearings conducted pursuant to these Hearing Procedures; the Hearing Officer shall not be a member of the Hearing Panel.~~

"Hearing Officer" means, solely for hearings conducted pursuant to Appendix 4E, (A) a CCC member or (B) an individual employed or contracted by NERC, as designated and approved by the CCC to preside over hearings conducted pursuant to the Hearing Procedures in Appendix E; the Hearing Officer shall not be a member of the Hearing Panel.

"Hearing Panel" means the five person hearing body established as set forth in the CCC Charter on a case by case basis and that is responsible for adjudicating a matter as set forth in ~~Paragraph~~ Section 1.1.1 above. ~~Specifically, the CCC shall not have a standing Hearing Panel. When a hearing is to be conducted, the CCC shall select five members to serve as the adjudicatory panel for that hearing. Members to serve on the Hearing Panel shall be selected by vote of a valid quorum of the CCC. Voting members of the CCC at arm's length from parties to the hearing may be nominated or volunteer to stand for selection to the Hearing Panel. One or more alternates may also be selected if the CCC deems appropriate for the circumstances. A member may serve on more than one Hearing Panel concurrently. A Hearing Panel is disbanded upon conclusion of the hearing proceedings for which it was formed.~~

~~"Hearing Officer" means, solely for hearings conducted pursuant to Appendix 4E, (A) a CCC member or (B) an individual employed or contracted by NERC, as designated and approved by the CCC to preside over hearings conducted pursuant to the Hearing Procedures in Appendix E; the Hearing Officer shall not be a member of the Hearing Panel.~~
"Participant" means a Respondent and any other Person who is allowed or required by the Hearing Panel or by FERC to participate as an intervenor in a proceeding conducted pursuant to these Hearing Procedures, and as used ~~herein~~in these Hearing Procedures shall include the members of the ~~Compliance~~ Staff of the CEA that participate in a proceeding.

~~"Penalty" as used herein includes all penalties and sanctions, including but not limited to a monetary or non-monetary penalty; a limitation on an activity, function, operation or other appropriate sanction; or the addition of the Respondent to a reliability watch list composed of major violators. Penalties must be within the range set forth in the NERC *Sanction Guidelines* approved by FERC pursuant to 18 C.F.R. Section 39.7(g)(2), and shall bear a reasonable relation to the seriousness of a Respondent's violation and take into consideration any timely efforts made by the Respondent to remedy the violation.~~

~~"Person" means any individual, partnership, corporation, limited liability company, governmental body, association, joint stock company, public trust, organized group of persons, whether incorporated or not, or any other legal entity.~~

~~"Reliable Operation" 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 Cyber Security Incident, or unanticipated failure of system Elements.~~

~~"Reliability Standards" means a requirement to provide for Reliable Operation of the Bulk Power System, including without limiting the foregoing, requirements for the operation of existing Bulk Power System Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge Bulk Power System Facilities or to construct new transmission capacity or generation capacity. A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority.~~

~~"Respondent" means the Registered Entity or Regional Entity who is the subject of the Notice of Alleged Violation, contested Mitigation Plan or contested Remedial Action Directive that is the basis for the proceeding, whichever is applicable.~~

~~"Staff" or "Compliance~~ "Staff" means individuals employed or contracted by NERC who have the authority to make initial determinations of compliance or violation with Reliability Standards by Registered Entities and associated Penalties ~~and~~, Mitigation ~~Plans.~~ Plans or Mitigating Activities.

~~"Technical Advisor" means any Staff member, third-party contractor, or industry stakeholder who satisfies NERC's conflict of interest policy and is selected to assist in a proceeding by providing technical advice to the Hearing Officer and/or the Hearing Panel.~~

1.2 General Provisions including Filing, Service, Transcription and Participation

1.2.1 Contents of Filings

All filings made with the ~~CCC~~Hearing Panel must contain:

(a) ~~**a)**~~ A caption that sets forth the title of the proceeding and the designated docket number or, if the filing initiates a proceeding, a space for the docket number;

(b) ~~**b)**~~ A heading that describes the filing and the Participant on whose behalf the filing is made;

(c) ~~**c)**~~ The full name, address, telephone number and email address of the Participant or the representative of the Participant making the filing;

(d) ~~d)~~ A plain and concise statement of any facts upon which the filing is based, which facts shall be supported by citations to the record of the hearing, if available, or other ~~documents~~evidence; and

(e) ~~e)~~ The specific relief sought, which may be in the alternative, and the authority that provides for or otherwise allows the relief sought.

1.2.2 Form of Filings

(a) ~~a)~~ All filings shall be typewritten, printed, reproduced, or prepared using a computer or other word or data processing equipment on white paper 8½ inches by 11 inches with inside text margins of not less than one inch. Page numbers shall be centered and have a bottom margin of not less than ½ inch. Line numbers, if any, shall have a left-hand margin of not less than ½ inch. The impression shall be on one side of the paper only and shall be double spaced; footnotes may be single spaced and quotations may be single spaced and indented.

(a) ~~b)~~ All pleadings shall be composed in either Arial or Times New Roman font, black type on white background. The text of pleadings or documents shall be at least 12-point. Footnotes shall be at least 10-point. Other material not in the body of the text, such as schedules, attachments and exhibits, shall be at least 8-point.

(b) ~~c)~~ Reproductions may be by any process provided that all copies are clear and permanently legible.

(c) ~~d)~~ Testimony prepared for the purpose of being entered into evidence shall include line numbers on the left-hand side of each page of text. Line numbers shall be continuous.

(d) ~~e)~~ Filings may include schedules, attachments, or exhibits of a numerical or documentary nature which shall, whenever practical, conform to these requirements; however, any log, graph, map, drawing, chart, or other such document will be accepted on paper larger than prescribed in subparagraph (a) if it cannot be provided legibly on letter size paper.

1.2.3 Submission of Documents

(a) ~~a)~~ **Where to File:** Filings shall be made with the NERC Director of ~~Compliance~~Enforcement located at ~~NERC's principal~~**NERC's Washington, DC** office. The office will be open ~~from 8 a.m. to 5 p.m., Eastern,~~during NERC's regular business hours each day except Saturday, Sunday, legal holidays and any other day declared by NERC.

(b) ~~b)~~ **When to File:** Filings shall be made within the time limits set forth in these Hearing Procedures or as otherwise directed by the Hearing Officer or the Hearing Panel. Filings will be considered made when they are date stamped when received by the NERC Director of ~~Compliance.~~ Enforcement. To be timely, filings must be received no later than ~~than~~ 5:00 p.m., ~~Eastern,~~local time on the date specified.

(c) ~~c)~~ **How to File:** Filings may be made by personal delivery, mailing documents that are properly addressed with first class postage prepaid, or depositing properly addressed documents with a private express courier service with charges prepaid or payment arrangements made. Alternatively, filing by electronic means will be acceptable upon implementation of a suitable and secure system ~~by the NERC Director of Compliance~~.

(d) ~~d)~~ **Number of Copies to File:** One original and ~~seven~~five exact copies of any document shall be filed. The ~~NERC Director of Compliance will~~Clerk will provide ~~the Hearing Officer, if any, and~~ each member of the Hearing Panel with a copy of each filing.

(e) ~~e)~~ **Signature:** The original of every filing shall be signed by the Participant on whose behalf the filing is made, either by an attorney of the Participant or, by the individual if the Participant is an individual, by an officer of the Participant if the Participant is not an individual, or if the Participant is Staff, by a designee

authorized to act on behalf of Staff. The signature on a filing constitutes a certificate that the signer has read the filing and knows its contents, and that the contents are true to the best of the signer's knowledge and belief.

(f) ~~f)~~ **Verification:** The facts alleged in a filing need not be verified unless required by these Hearing Procedures, the Hearing Officer, or the Hearing Panel. If verification is required, it must be under oath by a person having knowledge of the matters set forth in the filing. If any verification is made by an individual other than the signer, a statement must be included in or attached to the verification explaining why a person other than the signer is providing verification.

(g) ~~g)~~ **Certificate of Service:** Filings shall be accompanied by a certificate of service stating the name of the individuals served, the Participants whose interests the served individuals represent, the date on which service is made, the method of service, and the addresses to which service is made. The certificate shall be executed by the individual who caused the service to be made.

1.2.4 Service

(a) ~~a)~~ **Service List:** For each proceeding, the ~~**NERC Director of Compliance**~~Clerk shall prepare and maintain a list showing the name, address, telephone number, and facsimile number and email address, if available, of each individual designated for service. The Hearing Officer, NERC Director of ~~**Compliance**~~Enforcement and the ~~**Respondent's designated agent for service**~~Registered Entity's compliance contact as registered ~~**on**~~with the ~~**NERC Compliance Registry**~~CEA, shall automatically be included on the service list.

Participants shall identify all other individuals whom they would like to designate for service in a particular proceeding in their appearances or other filings. Participants may change the individuals designated for service in any proceeding by filing a notice of change in service list in the proceeding. Participants are required to update their service lists to ensure accurate service throughout the course of the proceeding. Copies of the service list may be obtained from the ~~NERC Director of Compliance.~~ Clerk.

(b) ~~b)~~ **By Participants:** Subject to the provisions of Section 1.5.10, a~~A~~ny Participant filing a document in a proceeding must serve a copy of the document on each individual whose name is on the service list for the proceeding. Unless otherwise provided, service may be made by personal delivery, email, and deposit in the United States mail properly addressed with first class postage prepaid, registered mail properly addressed with postage prepaid, or deposit with a private express courier service properly addressed with charges prepaid or payment arrangements made.

~~**c) By the NERC Director of Compliance**~~

(c) **Clerk:** The ~~**NERC Director of Compliance**~~Clerk shall serve all issuances of the Hearing Officer and Hearing Panel upon the members of the Hearing Panel and each individual whose name is on the service list for the proceeding. Service may be made by personal delivery, email, or ~~and~~ deposit in the United States mail properly addressed with first class postage prepaid, or registered mail properly addressed with postage prepaid, or deposit with a private express courier service properly addressed with charges prepaid or payment arrangements made. The ~~**Hearing Panel**~~ Clerk shall ~~**ensure that the NERC Director of Compliance has**~~transmit a copy of the record of a proceeding to the CEA at the time ~~**it issues**~~the CCC transmits to the CEA either (1) a Notice of Penalty, or (2) a Hearing Panel final order~~.~~ that includes a Notice of Penalty.

(d) ~~d)~~ **Effective Date of Service:** Service by personal delivery or email is effective immediately. Service by mail or registered mail is effective upon mailing; service by a private express courier service is effective upon delivery to the private express courier service. Unless otherwise provided, whenever a Participant has the right or is required to do some act within a prescribed period after the service of a document upon the Participant, four (4) ~~**calendar**~~ days shall be added to the prescribed period when the document is served upon the Participant by mail or registered mail.

1.2.5 Computation of Time

The time in which any action is required to be done shall be computed by excluding the day of the act or event from which the time period begins to run, and by including the last day of the time period, unless the last day is a Saturday, Sunday, legal holiday or any other day upon which the ~~NERC~~ office of the CEA is closed, in which event it also shall be excluded and the date upon which the action is required shall be the first succeeding day that is not a Saturday, Sunday, legal holiday, or day upon which the ~~NERC~~ office of the CEA is closed.

1.2.6 Extensions of Time

Except as otherwise provided by law, the time by which a Participant is required or allowed to act may be extended by the Hearing Officer or Hearing Panel for good cause upon a motion made before the expiration of the period prescribed. If any motion for extension of time is made after the expiration of the period prescribed, the Hearing Officer or Hearing Panel may permit performance of the act if the movant shows circumstances sufficient to justify the failure to act in a timely manner.

1.2.7 Amendments

Amendments to any documents filed in a proceeding may be allowed by the Hearing Officer or the Hearing Panel upon motion made at any time on such terms and conditions as are deemed to be just and reasonable.

1.2.8 Transcripts

(a) A full and complete record of all hearings, including any oral argument, shall be transcribed verbatim by a certified court reporter, except that the Hearing Officer ~~or the Hearing Panel~~ may allow off-the-record discussion of any matter provided the Hearing Officer ~~or the Hearing Panel~~ states the ruling on any such matter, and the Participants state their positions or agreement in relation thereto, on the record. The court reporter shall file a copy of each transcript with the Clerk. Upon receipt of a transcript from the court reporter, the Clerk shall send notice to the Participants stating that a transcript has been filed by the court reporter, the date or dates of the hearing that the transcript records, and the date the transcript was filed with the Clerk.

(b) Unless otherwise prescribed by the Hearing Officer ~~or the Hearing Panel~~, a Participant may file and serve suggested corrections to any portion of ~~the~~a transcript within ~~thirty-five (35) calendar~~fourteen (14) days from the date ~~on which the relevant portion~~ of the Clerk's notice that the transcript ~~was taken~~has been filed with the Clerk, and any responses shall be filed within ten (10) days after service of the suggested corrections. The Hearing Officer ~~or the Hearing Panel~~ shall determine what changes, if any, shall be made, and shall only allow changes that conform the transcript to the ~~truth~~statements being transcribed and ensure the accuracy of the record.

(c) ~~NERC~~The CEA will pay for transcription services, for a copy of the transcript for the record and for a copy of the transcript for ~~the Hearing Officer and the Hearing Panel.~~ Staff. Any other Participant shall pay for its own copy of the transcript if it chooses to obtain one and, should any Participant seek to obtain a copy of the transcript on an expedited basis, it shall pay for the expedited transcription services.

1.2.9 Rulings, Notices, Orders and Other Issuances

Any action taken by the Hearing Officer or the Hearing Panel shall be recorded in a ruling, notice, order or other applicable issuance, or stated on the record for recordation in the transcript, and is effective upon the date of issuance unless otherwise specified by the Hearing Officer or the Hearing Panel. All notices of hearings shall set forth the date, time and place of hearing.

1.2.10 Location of Hearings and Conferences

All hearings and oral arguments shall be held at ~~NERC's~~the principal office of the CEA unless the Hearing Officer or ~~the~~ Hearing Panel designates a different location.

1.2.11 Participant Participation

Participants may appear at any hearing via teleconference subject to the approval of the Hearing Officer ~~or~~and, in the event of oral argument, the Hearing Panel, except ~~that witnesses shall personally appear at the evidentiary hearing if~~as required by ~~Paragraph~~Section 1.6.6. Staff may participate and be represented by counsel in hearings, and shall have the rights and duties of any Participant.

1.2.12 Interventions ~~Are Not Permitted~~

(a) The Respondent(s) and Staff shall be Participants to the proceeding. Unless otherwise authorized by the Hearing Panel or by FERC ~~or another Applicable Governmental Authority (in the case of non-U.S. related proceedings),~~ no other Persons shall be permitted to intervene or otherwise become a Participant to the proceeding.

(b) The Hearing Panel may allow a Person to intervene only if the Hearing Panel determines that the Person seeking intervention has a direct and substantial interest in the outcome of the Alleged Violation, proposed Penalty or sanction, proposed Mitigation Plan or Mitigating Activities, or Remedial Action Directive that is the subject of the proceeding. Examples of a direct and substantial interest in the outcome shall include that the person seeking intervention:

(1) has received a Notice of Alleged Violation or a Remedial Action Directive involving the same Reliability Standard requirement(s) and arising out of the same event or occurrence as the existing Respondent(s) that is the subject of the proceeding, or

(2) will or may be contractually or legally liable to the original Respondent(s) for payment of all or a portion of the proposed Penalty or sanction that is the subject of the proceeding, provided, that after the Person seeking intervention sufficiently demonstrates it will or may be contractually or legally liable for payment of all or a portion of the proposed Penalty or sanction to be granted intervention, the Person granted intervention and the existing Respondents will not be allowed to litigate in the proceeding whether the Person granted intervention is contractually or legally liable for payment of all or a portion of the proposed Penalty or sanction or the amount of the proposed Penalty or Sanction for which the Person granted intervention is or may be liable.

That the Person seeking intervention has received a Notice of Alleged Violation for the same Reliability Standard Requirement(s) as the original Respondent(s) but arising out of a different event or occurrence; or seeks to intervene to advocate an interpretation of the Reliability Standard Requirement(s) or provision(s) of the Sanction Guidelines, that are at issue in the proceeding, without more, shall not constitute a direct and substantial interest in the outcome and shall not be grounds on which the Hearing Panel may allow the Person to intervene.

~~has received a Notice of Alleged Violation for the same Reliability Standard Requirement(s) as the original Respondent(s) but arising out of a different event or occurrence; or seeks to intervene to advocate an interpretation of the Reliability Standard Requirement(s) or provision(s) of the Sanction Guidelines, that are at issue in the proceeding, without more, shall not constitute a direct and substantial interest in the outcome and shall not be grounds on which the Hearing Panel may allow the Person to intervene.~~

(c) A Person seeking intervention shall do so by filing a motion to intervene with the Clerk. The motion shall state the Person's interest in sufficient factual detail to demonstrate that the Person should be allowed to

intervene pursuant to Section 1.2.12(b). The motion to intervene shall also state the Person's agreement to maintain the confidential and non-public nature of the hearing, including all pleadings and other documents filed or exchanged in connection with the request for intervention. Any facts alleged in, or offers of proof made in, the motion to intervene shall be supported by affidavit or verification.

(d) The Clerk shall promptly provide copies of the motion to intervene to the Hearing Officer and the Participants. The Hearing Officer shall promptly set a response period, not to exceed seven days, within which the Participants may file responses to the motion to intervene. Within seven (7) days following the end of the response period, the Hearing Officer shall issue a recommendation to the Hearing Panel as to whether or not the motion to intervene should be granted.

(e) The Hearing Panel may, within seven (7) days following the date of the Hearing Officer's recommendation, issue a decision granting or denying the motion to intervene. If the Hearing Panel does not issue a decision granting or denying the motion to intervene within seven (7) days following the date of the Hearing Officer's recommendation, the Hearing Officer's recommendation shall become the decision of the Hearing Panel and the motion to intervene shall be deemed granted or denied by the Hearing Panel in accordance with the Hearing Officer's recommendation.

(f) The Hearing Officer, on motion of a Participant or on his or her own motion, or the Hearing Panel, on recommendation by the Hearing Officer or its own motion, may stay or suspend the proceeding while a request to intervene, including a request to intervene filed directly with FERC, and including any appeal of the grant or denial of the request to intervene, is being resolved.

(g) A Person allowed to intervene and become a Participant to a proceeding shall be designated as a Respondent and deemed to be aligned with the existing Respondent(s), unless the Hearing Panel, in the decision granting intervention, states that the Person allowed to intervene shall be deemed to be aligned with another Participant to the proceeding.

(h) A Person may appeal a decision of the Hearing Panel denying the Person's motion to intervene, and the Staff, the Respondent or any other Participant may appeal a decision granting or denying a motion to intervene, in accordance with Section 414 of the NERC Rules of Procedure. A notice of appeal shall be filed with the NERC Director of Enforcement no later than seven (7) days following the date of the decision of the Hearing Panel granting or denying the motion to intervene.

1.2.13 Proceedings Closed to the Public

No hearing, oral argument, or meeting of the Hearing Panel shall be open to the public, and no notice, ruling, order, or any other issuance of the Hearing Officer or Hearing Panel, or any transcript, made in any proceeding shall be publicly released unless the ERO (within the U.S., in accordance with the authorization previously granted by FERC to release information about a non-public proceeding) or FERC (in the case of U.S.-related information) or another Applicable Governmental Authority (in the case of non-U.S.-related information) determines that public release is appropriate. Only the members of the Hearing Panel, the Participants, the Hearing Officer and the Technical Advisors, if any, shall be allowed to participate in or obtain information relating to a proceeding.

1.2.14 Docketing System

The ~~NERC Director of Compliance~~Clerk shall maintain a system for docketing proceedings. A docketed proceeding shall be created upon the ~~issuance~~filing of a ~~Notice of Alleged Violation or the findings of~~request for a ~~Regional Entity compliance program audit.~~ hearing. Unless NERC provides a different docketing system that will be used uniformly, docket numbers shall be assigned sequentially beginning with a two digit number that relates to the last two digits of the year in which the docket is initiated, followed by a dash ("-"), followed by the letters "~~NE~~[R~~C~~E]", followed by a dash ("-"), followed by a four digit number that will be "0001" on January 1 of each calendar year and ascend sequentially until December 31 of the same calendar year.

1.2.15 Representations Deemed to be made in All Pleadings

A Participant presenting any pleading to the Hearing Officer or Hearing Panel shall be deemed to certify that to the best of the Participant's knowledge, information and belief, formed after and based on an inquiry that is reasonable under the circumstances, that:

(a) the factual allegations set forth in the pleading have or will have support in the evidence or the Participant believes they will have support in the evidence after reasonable opportunity for further investigation or discovery;

(b) the denials in the pleading of factual allegations made by another Participant are warranted by or will be warranted by the evidence or, if specifically so identified, are reasonably based on belief or on a lack of information;

(c) the claims, defenses and other contentions set forth in the pleading are warranted based on the applicable Reliability Standard Requirement(s) or Rules of Procedure provisions; and

(d) the pleading is not being presented for any improper purpose, such as to harass, cause unnecessary delay, or needlessly increase the cost of the hearing or the cost incurred by any Participant.

1.2.16 Hold Harmless

A condition of a Participant invoking these Hearing Procedures and participating in a hearing is that the Participant agrees that the ~~NERC~~CEA and ~~the~~ CCC, including without limitation ~~their~~its Members, Board of Directors or Trustees, Compliance Committee, any other committees or subcommittees, Staff, contracted employees, Hearing Panel members, Hearing Officers and Technical Advisors, shall not be liable, and shall be held harmless against the consequences of, or any action or inaction arising out of, the hearing process, or of any agreement reached in resolution of a dispute or any failure to reach agreement as a result of a proceeding. This "hold harmless" provision does not extend to matters constituting gross negligence, intentional misconduct, or breach of confidentiality.

1.3 Initiation of the Hearing Process

~~Respondent's~~1.3.1 Registered Entity's Option to Request a Hearing

(a) Except when contesting a Remedial Action Directive pursuant to ~~Paragraph~~Section 1.9 of these Hearing Procedures, a ~~Respondent~~Registered Entity may file a statement, in accordance with Section 1.3.1(e), with the ~~NERC Director of Compliance~~ CCC requesting a hearing if either:

(1) ~~a) The Respondent~~the Registered Entity files ~~(i)~~ a response to a Notice of Alleged Violation that contests either the Alleged Violation, the proposed Penalty, or both~~, or (ii) a response that challenges a Regional Entity compliance program audit finding~~; or

(2) ~~b) The Compliance~~ the Staff submits to the ~~Respondent~~ Registered Entity a statement rejecting the ~~Respondent's~~Registered Entity's proposed revised Mitigation Plan or Mitigating Activities submitted after ~~Compliance~~ Staff rejected the ~~Respondent's~~Registered Entity's initial proposed Mitigation Plan~~.~~ or Mitigating Activities.

(b) A ~~Respondent~~ Registered Entity must file its hearing request within forty (40) ~~calendar~~ days after ~~(i)~~ :

(1) the ~~Respondent~~Registered Entity files its response to the Notice of Alleged Violation ~~or to the Regional Entity compliance program audit finding; or (ii)~~ ; or

~~(1)~~(2) the ~~Compliance~~ Staff submits to the ~~Respondent~~ Registered Entity its statement identifying a disagreement with the ~~Respondent's~~Registered Entity's proposed Mitigation Plan or Mitigating Activities, whichever is applicable.

(a) If the ~~Respondent~~Registered Entity does not file a hearing request within the ~~time~~ period set forth in this ~~Paragraph~~Section, then the ~~Respondent~~Registered Entity will be deemed to have agreed and waived any objection to the proposed Penalty, the Alleged Violation~~, the Regional Entity compliance program audit finding or the Compliance~~ or the Staff's rejection of the revised Mitigation Plan or Mitigating Activities, whichever is applicable.

(b) In accordance with Section 5.3 of the CMEP, a~~A~~ Notice of Alleged Violation issued to a ~~Respondent, a~~Registered Entity or a CEA Staff statement setting forth its rejection of a ~~Respondent's~~Registered Entity's proposed revised Mitigation Plan~~, or a report of the findings from a Regional Entity compliance program audit~~ or Mitigating Activities shall clearly state that the ~~Respondent~~Registered Entity has the option to contest the Alleged Violation ~~or~~, proposed Penalty, or both, ~~the Regional Entity compliance program audit finding, or the Compliance~~ or the Staff's rejection of the proposed revised Mitigation Plan or Mitigating Activities, using either the shortened hearing procedure pursuant to ~~Paragraph~~Section 1.3.~~2~~4 or the ~~full~~general hearing procedure described in ~~Paragraphs~~Sections 1.4 to 1.7.

(c) The Registered Entity's statement requesting a hearing shall:

(1) contain a plain and concise statement of the facts and arguments supporting the Registered Entity's position, as applicable, that it did not violate the Reliability Standard Requirement(s) set forth in the Notice of Alleged Violation, that the proposed Penalty or sanction is too high and should be reduced, or that the Registered Entity's proposed Mitigation Plan or Mitigating Activities should be approved;

(2) state the relief that the Registered Entity requests the Hearing Panel to ~~1.7.~~ grant; and

(3) state whether the Registered Entity requests the shortened hearing procedure or the general hearing procedure.

The Registered Entity's statement may set forth two or more alternative grounds on which the Registered Entity bases its position, as applicable, that it did not violate the Reliability Standard Requirement(s) set forth in the Notice

of Alleged Violation, that the proposed Penalty or sanction is too high and should be reduced, or that the Registered Entity's proposed Mitigation Plan or Mitigating Activities should be approved.

(d) If the ~~**Respondent**~~Registered Entity (or any Respondent if there are more than one Respondent) ~~**files a hearing request within the requisite time period, it shall state within its hearing request whether it**~~ requests the ~~**shortened**~~general hearing procedure ~~**pursuant to Paragraph 1.3.2 or the full**~~, the general hearing procedure ~~**described in Paragraphs 1.4 to 1.7.**~~ shall apply. If the ~~**Respondent**~~Registered Entity (or all Respondents if there are more than one Respondent) requests the ~~**full hearing procedure, the full hearing procedure shall apply. If the Respondent requests the**~~ shortened hearing procedure, ~~**Compliance**~~ Staff and any other Participants shall submit a filing within five (5) ~~**calendar**~~ days of the ~~**Respondent's**~~Registered Entity's hearing request that states whether Staff or such other Participant agrees to use the shortened hearing procedure. If Staff or another Participant makes a filing requesting the ~~**full**~~general hearing procedure, then the ~~**full**~~general hearing procedure shall apply; otherwise the shortened hearing procedure requested by the ~~**Respondent**~~Registered Entity or ~~**Respondents**~~entities shall be used. Once either the ~~**full**~~general or shortened hearing procedure has been selected, the Participants shall not be allowed to revert to the non-selected hearing procedure unless the Participants mutually agree.

A Registered Entity shall attach to its request for hearing ~~request shall include:~~

~~a) A concise statement of the error or errors contained in the decision being appealed;~~

~~b) A clear statement of the relief being sought;~~

~~c) Argument in sufficient detail to justify such relief; and~~

(e) ~~d) Attachments of the full text of the decision being appealed and~~ whichever of the following are applicable:

(1) ~~**1)**~~ The ~~**Respondent's**~~Registered Entity's Self-Report~~**ing**~~ of a violation;

(2) ~~**2)**~~ The Notice of Alleged Violation and the ~~**Respondent's**~~Registered Entity's response thereto; and/or

~~3) The report of the Regional Entity compliance program audit and the Respondent's response thereto; and/or~~

(3) ~~4) The Respondent's~~Registered Entity's proposed revised Mitigation Plan or Mitigating Activities and the ~~Compliance~~ Staff's statement rejecting the proposed revised Mitigation Plan~~.~~ or Mitigating Activities.

1.3.2 Staff's Response to Request for Hearing

(a) If the Registered Entity requests that the shortened hearing procedure be used, the Staff shall file a response stating whether it agrees to the use of the shortened hearing procedure.

(b) If the Registered Entity requests that its proposed revised Mitigation Plan or Mitigating Activities should be approved, the Staff shall file a response stating the Staff's position as to why the Registered Entity's proposed revised Mitigation Plan or Mitigating Activities should not be approved and setting forth any additional terms that the Staff believes should be included in the Mitigation Plan or Mitigating Activities.

(c) If the Registered Entity does not request that the shortened hearing procedure be used and does not request that the Registered Entity's proposed revised Mitigation Plan or Mitigating Activities should be approved, the Staff may, but is not required to, file a response stating, as applicable, the basis for the Staff's position that the Registered Entity violated the Reliability Standard Requirement(s) specified in the Notice of Alleged Violation or that the proposed Penalty or sanction is appropriate under the Sanction Guidelines and should not be reduced.

(d) Any response by the Staff required or permitted by this Section shall be filed within fifteen (15) days after the date the request for hearing was filed, unless the Hearing Officer or Hearing Panel allows a longer time to file the response.

1.3.3 Notice of Hearing

(a) The Clerk shall issue a notice of hearing not less than sixteen (16) days, and not more than twenty-one (21) days, after the Registered Entity files its request for hearing.

(b) The notice of hearing shall state whether the shortened hearing procedure or the general hearing procedure will be used.

(c) The notice of hearing shall identify the Hearing Officer and the date, time and place for the initial prehearing conference.

(1) If the shortened hearing procedure is to be used, the initial prehearing conference shall be set for a date within seven (7) days following the date of the notice of hearing.

(2) If the general hearing procedure is to be used, the initial prehearing conference shall be set for a date within fourteen (14) days following the date of the notice of hearing.

1.3.4 Shortened Hearing Procedure

The shortened hearing procedure shall be as set forth in this ~~Paragraph.~~ Section. The rules applicable to the ~~full~~general hearing procedure shall apply to the shortened hearing procedure unless the context of such a rule is inconsistent with the procedure set forth in this ~~Paragraph~~Section or otherwise renders it inapplicable to the shortened hearing procedure. The rules concerning ex parte communications in ~~Paragraph~~Section 1.4.7 are hereby expressly made applicable to the shortened hearing procedure under this ~~Paragraph.~~ Section.

The Hearing Panel ~~may utilize~~shall use a Hearing Officer to preside over the shortened hearing procedure in accordance with ~~Paragraph~~Section 1.4.2. ~~But, no evidentiary~~No testimonial hearing ~~Testimonial H~~hearing will be held in the shortened hearing procedure and the Participants will not present witness testimony or file briefs, except that briefs on exceptions and briefs in reply to exceptions may be allowed pursuant to ~~Subparagraph~~subsection (g). Instead, the following events shall take place within the following periods:

(a) ~~a)~~ The initial prehearing conference shall be held within seven (7) ~~calendar~~ days after the date on which the notice of hearing is issued. In addition to any other matters set forth in ~~Paragraph~~Section 1.5.2 that may apply, the initial prehearing conference will be used to develop a schedule for the preparation and submission of comments in accordance with ~~Subparagraphs~~subsections (c) through (e).

(b) ~~b)~~ Within ~~five (5) calendar~~ten (10) days after the date on which the notice of hearing is issued, Staff shall make documents available to the ~~Respondent~~Registered Entity for inspection and copying pursuant to ~~Paragraph~~Section 1.5.7.

(c) ~~c)~~ Within twenty-one (21) ~~calendar~~ days after the initial prehearing conference, the Staff shall file:

(1) ~~1)~~ initial comments stating Staff's position on all issues and the rationale in support of its position, including all factual and legal arguments;

(2) ~~2)~~ all Documents that Staff seeks to introduce in support of its position that have not already been submitted in the proceeding; and

(3) ~~3)~~ a verification attesting to the truthfulness of the facts alleged in the filing.

(d) ~~d)~~ Within fourteen (14) ~~calendar~~ days of Staff's initial comment filing pursuant to ~~Subparagraph~~subsection (c), the ~~Respondent~~Registered Entity shall file:

(1) ~~1)~~ responsive comments stating the ~~Respondent's~~Registered Entity's position on all issues and the rationale in support of its position, including all factual and legal arguments, which ~~comment~~ also may respond to Staff's initial comments;

(2) ~~2)~~ all Documents that the ~~Respondent~~Registered Entity seeks to introduce in support of its position that have not already been submitted in the proceeding; and

(3) ~~3)~~ a verification attesting to the truthfulness of the facts alleged in the filing.

(e) ~~e)~~ Within seven (7) ~~calendar~~ days after the ~~Respondent's~~Registered Entity's responsive comment filing ~~pursuant to Subparagraph (d),~~ Staff shall file reply comments that shall be limited in scope to responding to the ~~Respondent's~~Registered Entity's responsive comments and be supported by a verification attesting to the truthfulness of the facts alleged in the filing. Staff shall not submit any additional Documents in support of its position as part of this filing except upon motion and good cause shown. If Staff is allowed to file additional Documents in support of its position based upon such a motion, the ~~Respondent~~Registered Entity shall have the right to file additional Documents in support of its position that are responsive to the additional Documents that Staff is allowed to file provided that any additional ~~Respondent~~Registered Entity filing also shall be verified.

(f) ~~f)~~ The Hearing Officer shall issue an initial opinion within twenty-one (21) ~~calendar~~ days after the Staff's reply comments filing or any additional filing by the ~~Respondent~~Registered Entity pursuant to ~~Subparagraph~~subsection (e).

(g) ~~g)~~ If either Participant requests, the Hearing Officer shall allow each Participant to file, within seven (7) ~~calendar~~ days after the Hearing Officer's initial opinion, exceptions to the Hearing Officer's initial opinion in a brief designated "brief on exceptions" in accordance with ~~Paragraph~~Section 1.7.5 and within seven (7) ~~calendar~~ days thereafter, a reply brief designated "b~~B~~rief in r~~R~~eply to e~~E~~xceptions."

(h) ~~h)~~ The Hearing Panel shall strive, but is not required, to issue a final order within ~~ninety (90) calendar~~one hundred twenty (120) days of the notice of hearing. The Hearing ~~Body~~Panel may extend this deadline for good cause and shall provide written notice of any extension to all Participants.

The Hearing Officer or Hearing Panel may modify any ~~time~~ period set forth within this Paragraph as warranted by the circumstances but it will be the objective of the Hearing Panel to issue the final order within ~~ninety (90) calendar~~one hundred twenty (120) days of the notice of hearing.

1.4 General Hearing Procedure

~~1.4.1 Notice of Hearing~~

~~Within seven (7) calendar days of a Respondent requesting a hearing pursuant to Paragraph 1.3, the NERC Director of Compliance shall issue a notice of hearing in the docket. The notice of hearing shall identify the Hearing Officer, if designated at that time, and the date, time, and place for the prehearing conference, which should occur no later than fourteen (14) calendar days after the notice of hearing is issued.~~

1.4.1 [Intentionally Left Blank]

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1.4.2 Hearing Officer

(a) The CCC ~~may utilize~~shall use a Hearing Officer to preside over each hearing conducted pursuant to these Hearing Procedures, provided that the Hearing Officer's actions shall be subject to the authority of the Hearing Panel as set forth in ~~Paragraph~~Section 1.4.3. Members of the Hearing Panel may attend any aspect of the hearing.

(b) The Hearing ~~Panel may delegate to the Hearing~~ Officer ~~authority over~~is responsible for the conduct of the hearing, including administering the hearing from the initial prehearing conference through the issuance of the Hearing Officer's initial opinion ~~and~~, any administrative hearing functions thereafter, and ~~the responsibility for~~ submission of the matter to the Hearing Panel for final decision through the presentation to the Hearing Panel of an initial opinion. The Hearing Officer shall have those duties and powers necessary to those ends, consistent with and as further enumerated in these Hearing Procedures, including the following:

(1) ~~a)~~ To administer oaths and affirmations;

(2) ~~b)~~ To schedule and otherwise regulate the course of the hearing, including the ability to call to recess, reconvene, postpone or adjourn a hearing;

(3) ~~c)~~ Consistent with any timing or deadline requirements imposed by these Hearing Procedures or by applicable law, to separate any issue or group of issues from other issues in a proceeding and treat such issue(s) as a separate phase of the proceeding;

(4) ~~d)~~ Consistent with any timing or deadline requirements imposed by these Hearing Procedures or by applicable law, to modify any time period, if such modification is in the interest of justice and will result in no undue prejudice to any other Participant;

(5) ~~e)~~ To supervise and issue orders concerning discovery;

(6) ~~f)~~ To conduct prehearing conferences, status hearings, and evidentiary hearings;

(7) ~~g)~~ To hear argument on all objections, motions and other requests, and t~~T~~o rule upon all objections, motions and other requests that do not result in the final determination of the proceeding;

(8) ~~h)~~ To rule on and receive evidence;

(9) ~~i)~~ To call upon a Participant to produce further evidence that is material and relevant to any issue;

(10) ~~j)~~ To issue protective orders pursuant to ~~Paragraph~~Section 1.5.10;

(11) ~~k)~~ To issue initial opinions; and

(12) ~~l)~~ To ensure that hearings are conducted in a full, fair, and impartial manner, that order is maintained and that unnecessary delay is avoided in the disposition of the proceedings.

~~If the Hearing Panel uses a Hearing Officer to preside over a hearing, the Hearing Panel~~ The CCC shall disclose the ~~identity,~~ employment history and professional affiliations of the Hearing Officer within two (2) ~~calendar~~ days of the Hearing Officer's assignment to the proceeding, and Participants to the hearing may raise objections to the Hearing Officer's participation in accordance with ~~Paragraph~~Section 1.4.5.

1.4.3 Hearing Panel

(a) The CCC shall not have a standing Hearing Panel. When a hearing is to be conducted, the CCC shall select five members to serve as the adjudicatory panel for that hearing. Members to serve on the Hearing Panel shall be selected by vote of a valid quorum of the CCC. Voting members of the CCC at arm's length from parties to the hearing may be nominated or volunteer to stand for selection to the Hearing Panel. One or more alternates may also be selected if the CCC deems appropriate for the circumstances. A member may serve on more than one Hearing Panel concurrently. A Hearing Panel is disbanded upon conclusion of the hearing proceedings for which it was formed.

~~1.4.3~~(b) The composition of the Hearing Panel, after any recusals or disqualifications, shall be such that no two industry sectors may control, and no single industry sector may veto, any decision of the Hearing Panel on any matter brought before it for decision. "Hearing Panel" means the five person Hearing Panel established as set forth in the CCC Charter on a case by case basis and that is responsible for adjudicating a matter as set forth in Section 1.1.1 above.

(a) The Hearing Panel is vested with the authority to issue a final order resolving the issue(s) in all cases. To that end:

(1) ~~a) The Hearing Panel shall receive all filings in a hearing, including but not limited to all issuances of the Hearing Officer, all motions and responses thereto, and all written comments, testimony and evidence.~~ Upon receiving a filing by a Participant, the Clerk shall promptly send a notice to the members of the Hearing Panel identifying the date of the filing and the Participant making the filing and briefly describing the nature of the filing. Any member of the Hearing Panel may request of, and shall receive from, the Clerk, a copy of any filing by a Participant. The Hearing Panel shall not receive Documents made available by Staff for inspection and copying by the Respondent, or other responses to discovery between the Participants, unless such Documents are placed into the record pursuant to ~~Paragraph~~Section 1.6.7.

(2) ~~b)~~ The Clerk shall send all issuances of the Hearing Officer to the members of the Hearing Panel.

(3) The Hearing Panel or any individual member thereof may, but is not required to, attend any prehearing conference, status hearing or e~~E~~evidentiary h~~H~~earing, and/or to submit questions to the Hearing Officer to submit to a Participant or any witness at any ~~such hearing.~~ hearing. At any prehearing conference or hearing attended by a member of the Hearing Panel, any member of the Hearing Panel may ask questions directly of any Participant or witness.

(4) ~~c)~~ The Hearing Panel shall have the same authority as the Hearing Officer, as set forth in these Hearing Procedures, to require the Participants or any individual Participant to: (i) address a specific issue in testimony, evidence or briefs; (ii) present oral argument on an issue; (iii) file pre-evidentiary hearing memorandums; or (iv) produce further evidence that is material and relevant to any issue. To this end, the Hearing Panel shall be entitled to issue questions or requests for information to any Participant or any witness at any time until the issuance of a final order.

To the extent that the Hearing Panel disagrees with any issuance or ruling of the Hearing Officer, it may, on its own motion or upon petition for interlocutory review meeting the requirements of Section 1.4.4, reverse

or modify the issuance or ruling in whole or in part, or take any other action as may be appropriate. ~~d) To the extent that the Hearing Panel disagrees with any issuance or ruling of the Hearing Officer, it may, on its own motion or upon petition for interlocutory review meeting the requirements of Paragraph~~Section 1.4.4, ~~reverse or modify the issuance or ruling in whole or in part, or take any other action as may be appropriate.~~

(5) ~~e)~~ The Hearing Panel shall resolve the issue(s) in every hearing through the issuance of a final order. In issuing a final order, the Hearing Panel shall consider the Hearing Officer's initial opinion but shall have the authority to reject, modify, or approve the initial opinion in whole or in part.

1.4.4 Interlocutory Review

(a) A Participant shall be allowed to seek interlocutory review by the Hearing Panel of any ruling of the Hearing Officer where the ruling for which interlocutory review is sought presents an extraordinary circumstance which makes prompt review necessary to prevent prejudice to a Participant's ability to present its position in the proceeding. Failure to seek such review shall not operate as a waiver of any objection to such ruling.

(a) Unless good cause is shown or unless otherwise ordered by the Hearing Officer or the Hearing Panel, the Participant seeking review shall file a petition for interlocutory review within fourteen (14) ~~calendar~~ days after the date of the action that is the subject of the petition. The petition shall contain, in a separately identified section, a demonstration that the ruling for which interlocutory review is sought presents an extraordinary circumstance which makes prompt review necessary to prevent prejudice to the Participant's ability to present its position in the proceeding. The petition shall be filed with any offer of proof and supported by references to the record, or by affidavit if based on facts that do not appear ~~of~~in the record. Responses to petitions for interlocutory review shall be filed within seven (7) ~~calendar~~ days after service of the petition. No replies to responses ~~are~~shall be allowed.

(b) The Hearing Officer shall file a report to the Hearing Panel within fourteen (14) ~~calendar~~ days from the filing of the petition. The Hearing Officer's report shall set forth the relevant facts and other background information relating to the ruling on which interlocutory review is sought, the basis for the Hearing Officer's ruling, a summary of the Participants' arguments on the petition for interlocutory review, and the recommendation of the Hearing Officer for the disposition of the petition by the Hearing Panel.

~~(a)~~(c) On review of a Hearing Officer's ruling, the Hearing Panel may affirm or reverse the ruling in whole or in part, and may take any other just and reasonable action with respect to the ruling, such as declining to act on an interlocutory basis. The Hearing Panel may reject the petition for interlocutory review on the grounds that the ruling for which review is sought does not present an extraordinary circumstance which makes prompt review necessary to prevent prejudice to a Participant's ability to present its position in the proceeding, without considering or ruling on the substance of the petitioner's arguments.

(d) Issuance of a ruling on a petition for interlocutory review shall require (i) a quorum (as defined in ~~Paragraph~~Section 1.7.8) of the Hearing Panel, and (ii) a majority vote of the members of the Hearing Panel voting on the final order (in which the number of members voting shall not be less than a quorum). Petitions to rehear or reconsider the Hearing Panel's action taken on interlocutory review shall not be allowed. Filing and disposition of a petition for interlocutory review of a ruling of the Hearing Officer shall not suspend or otherwise delay a hearing or any other scheduled dates in the proceeding except as authorized by the Hearing Officer or the Hearing Panel based on a finding of exceptional circumstances.

(e) A non-Participant that has been ordered by the Hearing Officer pursuant to ~~paragraph~~Section 1.5.8 to produce or provide Documents, information or testimony, and has failed to obtain the relief sought from the Hearing Officer through filing objections to or a motion to quash the order, shall also be entitled to seek interlocutory review by the Hearing Panel of the Hearing Officer's order, with respect to (i) whether the non-Participant is within the class of Persons subject to such orders pursuant to ~~paragraph~~Section 1.5.8, and (ii)

the reasonableness of the Hearing Officer's order to produce or provide Documents, information or testimony.

1.4.5 Disqualification

(a) A Hearing Officer, Technical Advisor or member of the Hearing Panel shall recuse himself or herself from a proceeding if participation would violate ~~the~~ NERC's applicable conflict of interest policy.

(b) Any Participant may file a motion to disqualify or for recusal of a Hearing Officer, Technical Advisor or member of the Hearing Panel from a proceeding on grounds of a conflict of interest, an ex parte communication prohibited by ~~Paragraph~~Section 1.4.7, or the existence of other circumstances that could interfere with the impartial performance of his or her duties. The Participant shall set forth and support its alleged grounds for disqualification by affidavit. A motion for disqualification shall be filed within fifteen (15) ~~calendar~~ days after the later of: (1) the time when the Participant learns of the facts believed to constitute the basis for disqualification; or (2) the time when the Participant is notified of the assignment of the Hearing Officer or Technical Advisor.

(c) The Hearing Officer shall issue a proposed ruling for the Hearing Panel's consideration upon the filing of a motion for disqualification unless the Hearing Officer is the subject of the motion. The Hearing Panel, without the participation of any member who is the subject of the motion, shall issue a final ruling on the motion. If the Hearing Officer ~~is recused or~~recuses himself or herself or is disqualified, the Hearing Panel will appoint a replacement Hearing Officer. To ensure fairness to the Participants and expedite completion of the proceeding when a replacement Hearing Officer is appointed after a hearing has commenced, the replacement Hearing Officer may recall any witness or may ~~certify~~take other steps necessary to ensure familiarity with any part or all of the record.

(d) If a quorum (as defined in ~~Paragraph~~Section 1.7.8) of the Hearing Panel does not remain after any recusals and rulings on motions for disqualification, then the CCC shall appoint ~~a~~at least the number of new ~~member(s)~~members to the Hearing Panel necessary to create a quorum~~, which~~. The new member(s) shall serve on the Hearing Panel through the conclusion of the proceeding but not thereafter. ~~The CCC shall only appoint the number of new members as are necessary to create a quorum.~~ Any new member of the Hearing Panel shall be subject to the provisions applicable herein to all Hearing Panel members.

1.4.6 Technical Advisor

(a) The Hearing Officer and/or the Hearing Panel may elect to use one or more Technical Advisors to assist in any proceeding. Such an election may be made at any time during the course of a proceeding. Any Staff member who serves as a Technical Advisor shall not have been involved in or consulted at any time in regard to any ~~Compliance~~ Staff investigation, ~~initial~~ determination of a Possible Violation, Alleged Violation or Penalty, ~~Regional Entity compliance program audit,~~ or assessment of a ~~Respondent's~~Registered Entity's proposed Mitigation Plan or Mitigating Activities that resulted in the proceeding in which technical advice would be rendered, and shall not be a member of Staff participating in the proceeding on which such technical advice would be rendered.

(b) If the Hearing Officer or Hearing Panel uses a Technical Advisor to assist in any hearing, the Hearing Officer or Hearing Panel shall disclose the identity, employment history and professional affiliations of the Technical Advisor within two (2) ~~calendar~~ days of the Technical Advisor's assignment to the proceeding, and Participants to the hearing may raise objections to the Technical Advisor's participation in accordance with ~~Paragraph~~Section 1.4.5.

1.4.7 No Ex Parte Communications

Once a Registered Entity requests a hearing pursuant to Section 1.3.1:~~a) Once a RespondentRegistered Entity requests a hearing pursuant to ParagraphSection 1.3:~~

(a) ~~1)~~ :

(1) neither the Hearing Panel, the Hearing Officer, nor the Technical Advisor(s), if any, may communicate either directly or indirectly with any Person concerning any issue in the proceeding outside of the hearing process; except that

(2) ~~2)~~ the Hearing Panel, the Hearing Officer, and the Technical Advisor(s), if any, may communicate outside of the hearing process either directly or indirectly with a Participant or a Participant's representative:

i. ~~A)~~ in writing if the writing is simultaneously provided to all Participants; ~~or~~

ii. ~~B)~~ orally if a representative for every Participant is present in person or by telephone; or

iii. ~~C)~~ subject to the requirement that the substance of any ruling on any issue discussed shall be memorialized on the record or by the issuance of a notice or ruling, and that any Participant objecting to the ruling shall have the opportunity to state its objection on the record.

(b) ~~b)~~ Exceptions

(1) The proscription in ~~Subparagraph~~subsection (a)(1) does not prohibit members of the ~~Compliance~~ Staff from communicating with the ~~Respondent~~Registered Entity, and representatives, agents or employees thereof on any topic, provided that any member of the ~~Compliance~~ Staff involved in any such communication relating to the subject matter of the proceeding may not be, and may not subsequently serve as, a Technical Advisor.

(2) ~~c)~~ The proscription in ~~Subparagraph~~subsection (a)(1) ~~also~~ does not prohibit communications between or among members of the Hearing Panel, the Hearing Officer, and any Technical Advisor.

(3) ~~d)~~ The proscription in subsection (a)(1) does not prohibit communications between the Hearing Officer or members of the Hearing Panel to the Clerk for the purpose of transmitting documents, giving instructions to the Clerk, or discussing scheduling and other procedural matters relating to the proceeding.

(4) The proscription in subsection (a)(1) does not prohibit communications between or among the Clerk, the Hearing Panel and representatives of the CEA for purposes of establishing the hearing forum.

(c) Any member of the Hearing Panel, the Hearing Officer or any Technical Advisor who receives or who makes or knowingly ~~causes to be made~~allows a communication prohibited by this ~~Paragraph~~Section shall, within seven (7) ~~calendar~~ days of the communication, file and serve on the Participants in the proceeding a notice of ex parte communication setting forth the date, time and place of communication, a summary of the substance and nature of the communication and all responses thereto, and a list of each Person who made or received the communication and, if the communication or any response thereto was in writing, a copy of the written communication shall be attached.

1.4.8 Appearances

(a) Participants shall file written appearances within seven (7) ~~calendar~~ days after the notice of hearing is issued. A Participant's written appearance shall identify the name(s) of each individual authorized to represent the Participant in the proceeding exclusive of witnesses. An individual may appear on his or her own behalf. A

corporation, limited liability company, association, partnership, or governmental body may appear by any bona fide officer or designee who has the authority to act on behalf of the Participant. A Participant also may appear by an attorney.

(a) A Participant's written appearance shall state, with respect to each individual that the Participant identifies for service, the individual's name, address, telephone number, and facsimile number and email address, if available, where service shall be made.

(b) A Participant may withdraw any individual from the Participant's representation or otherwise change the identity of individuals authorized to represent the Participant in a proceeding by filing a notice of a change in service list.

(c) Any attorney appearing on behalf of a Participant shall be licensed to practice law and in good standing before the Supreme Court of the United States or the highest court of any State, territory of the United States or the District of Columbia ~~or of another Applicable Governmental Authority (in the case of non-U.S. related proceedings).~~. All representatives appearing before the Hearing Panel or Hearing Officer shall conform to the standards of ethical conduct required of practitioners before the courts of the United States.

(d) Individuals representing Participants in any hearing also shall enter their appearances at the beginning of the hearing by stating their names, addresses, telephone numbers, and email addresses orally on the record.

1.4.9 Failure to Appear or Exercise Diligence

The failure of any Participant to appear during any hearing without good cause and without notification may be grounds for dismissal or deciding against the interests of such Participant.

1.4.10 Consolidation of Proceedings

(a) In the event that more than one ~~Respondent~~Registered Entity receives a Notice of Alleged Violation for the same event or ~~transaction~~occurrence, and each ~~Respondent~~Registered Entity selects the ~~full~~general hearing procedure described in ~~Paragraphs~~Sections 1.4 to 1.7, the Hearing Panel on its own motion or on motion of a Participant may exercise its discretion to examine the actions of all ~~Respondents~~such Registered Entities in a single proceeding as long as an initial opinion has not been rendered by the Hearing Officer pursuant to ~~Paragraph~~Section 1.7.4 in any proceeding to be consolidated.

(b) A Participant may file a motion ~~pursuant to Paragraph 1.5.5~~ to consolidate into a single proceeding ~~allegations of~~alleged violations of different Reliability Standards against a single Respondent, and related contests of Penalties ~~or~~, Mitigation ~~Plans~~Plan or Mitigating Activities, arising out of the same event or ~~transaction.~~ occurrence. Such consolidation may be allowed in the discretion of the Hearing Officer or Hearing Panel, as applicable.

1.5 Prehearing Procedure

1.5.1 [Intentionally ~~left blank.~~]Left Blank]

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1.5.2 Prehearing Conference

(a) The ~~purpose of the~~ Hearing Officer shall hold at least one prehearing conference ~~shall~~, which may be the initial prehearing conference or a subsequently scheduled prehearing conference, in order to:

(1) ~~a)~~ Preliminarily identify the issues and discuss the anticipated form of the hearing;

(2) ~~b)~~ Discuss a schedule for any discovery to be conducted and address any discovery issues that are raised at that time;

(3) ~~c)~~ Explore the possibility of obtaining admissions of fact and of the ~~genuineness~~authenticity of documents that would avoid unnecessary proof;

(4) ~~d)~~ Develop a schedule for the preparation and submission of evidence and witness testimony, including the disclosure of witnesses and exhibits and whether the use of pre-filed testimony may not be appropriate, in advance of the evidentiary hearing;

(5) ~~e)~~ Develop a schedule or schedules for any anticipated motions;

(6) Schedule a date(s) for the e~~E~~evidentiary h~~H~~hearing, which shall be within ninety (90) days of the prehearing conference described in this subsection, unless a different date or dates is specified by the Hearing Officer or the Hearing Panel and with the consent of all Participants or for good cause shown; and

(7) ~~f)~~ Address such other matters as may aid in the simplification of the evidence and disposition of the proceeding.

(b) The Hearing Officer shall also hold a final prehearing conference prior to the evidentiary hearing~~Evidentiary Hearing~~, for the purpose of discussing:

(1) the anticipated duration of the hearing;

(2) the scheduling of witnesses' appearances to testify;

(3) the issues anticipated to be presented at the hearing;

(4) whether prehearing memoranda should be filed and if so, the schedule; and

(5) any other matters identified by the Hearing Officer for the management of the evidentiary hearing~~Evidentiary Hearing~~.

Participants may submit to the Hearing Officer, at least ten (10) days prior to the scheduled date of the final prehearing conference, a proposed list or lists of matters to be discussed at the final prehearing conference.

1.5.3 Summary Disposition

(a) Availability: A Hearing Officer, on the Hearing Officer's own motion or on the motion of a Participant, may issue an initial opinion granting, in whole or in part, summary disposition if it appears that there are no issues of material fact~~.~~ and a Participant is entitled to issuance of a final order in its favor.

(b) Motion for Summary Disposition and Responses

(1) A Participant moving for summary disposition must clearly identify the material facts that are not in dispute, demonstrate that there are no other material facts in dispute, and demonstrate that on the basis of the undisputed material facts, the Participant is entitled to issuance of a final order in its favor.

(2) A Participant opposing a motion for summary disposition must clearly identify in its response to the motion the material facts that the Participant contends remain in dispute, and/or explain why the moving Participant is not entitled to issuance of a final order in its favor even though there are no disputed issues of material fact.

(c) Summary Disposition on the Hearing Officer's Own Motion: If the Hearing Officer is considering summary disposition in the absence of a Participant motion, the Hearing Officer shall request the Participants to identify in writing any issues of material fact and to comment on the proposed disposition. Factual information in the Participants' comments shall be supported by affidavit. Following review of the Participants' comments, if it still appears to the Hearing Officer that there are no genuine issues of material fact, the Hearing Officer may proceed without an evidentiary hearing. The Hearing Officer shall, however, allow the Participants the opportunity to file briefs. ~~**When the Hearing Officer issues an initial opinion granting a motion for summary disposition in whole or in part, the ruling shall set forth the rationale for the grant. An initial opinion of the Hearing Officer granting summary disposition shall be confirmed, rejected or modified in a final order issued by the Hearing Panel.**~~

(d) Hearing Officer's Initial Opinion Granting Summary Disposition: When the Hearing Officer issues an initial opinion granting summary disposition in whole or in part, the ruling shall set forth the rationale for the grant. An initial opinion of the Hearing Officer granting summary disposition shall be confirmed, rejected, or modified in a final order issued by the Hearing Panel.

1.5.4 Status Hearings

Any Participant may request, and the Hearing Officer may call, a status hearing at any time subsequent to the initial prehearing conference to address issues that have arisen between the Participants~~.~~ or other matters relevant to the conduct of the hearing. Such issues may include, but are not limited to, discovery disputes and scheduling matters. A Participant requesting a status hearing to resolve a dispute shall include in its request a certification that it has made a good faith effort to resolve the dispute with the other Participant(s) before requesting the status hearing. The Hearing Officer shall direct the ~~NERC Director of Compliance~~Clerk to issue a notice of status hearing that sets forth the date, time, and place for the hearing, and that identifies the matters to be addressed at the hearing.

1.5.5 Motions and Responses

(a) Unless otherwise provided in these Hearing Procedures or by the procedural schedule established by the Hearing Officer or Hearing Panel, a Participant may file a motion at any time requesting any relief as may be appropriate. Unless ~~a~~the Hearing Officer allows a motion to be made orally on the record, motions shall be filed in writing. Motions based on facts that do not appear ~~of~~ on the record shall be supported by affidavit.

(a) Unless otherwise specified by the Hearing Officer or Hearing Panel, responses to motions shall be filed within fourteen (14) ~~**calendar**~~ days after service of the motion, and replies to responses shall be filed within seven (7) ~~**calendar**~~ days after service of the responses~~**; however, a**~~. A Hearing Officer or Hearing Panel may deny dilatory, repetitive, or frivolous motions without awaiting a response. Unless otherwise ordered by a Hearing Officer or Hearing Panel, the filing of a motion does not stay the proceeding or extend any scheduled dates in the proceeding.

1.5.6 Experts

(a) A Participant may employ an expert(s) to testify or consult in a proceeding. Any expert utilized in either capacity shall sign an agreement evidencing the expert's understanding and acknowledgement of the non-public nature of the proceeding and that unauthorized public disclosure of information obtained in connection with the expert's participation in the proceeding is prohibited.

(b) The Participant employing the expert shall propose the agreement for approval ~~via~~by a motion, and its approval shall be subject, in addition to consideration of any objections by other Participants, to ensuring that appropriate safeguards are maintained to protect the confidentiality of the proceeding and the information disclosed therein.

1.5.7 Inspection and Copying of Documents in Possession of Staff

(a) ~~a)~~ **Documents to be Available for Inspection and Copying**

(1) ~~(1)~~ Within twenty-five (~~5) calendar~~25) days after ~~issuance of~~ the ~~notice of~~ date the request for hearing is filed, Staff shall make available for inspection and copying by the ~~Respondent~~other Participants, all Documents prepared or obtained by Staff through or in connection with any compliance monitoring ~~process(es)~~processes that led to the institution of proceedings. Such Documents shall include but are not limited to:

i. ~~(A)~~ requests for information to the Respondent;

ii. ~~(B)~~ every written request, including e-mail, directed to persons not employed by ~~NERC~~the CEA to provide information or documents or to be interviewed;

iii. ~~(C)~~ the Documents provided in response to any such requests described in (~~A~~i) and (~~B~~ii) above;

iv. ~~(D)~~ all transcripts of testimony recorded during the Staff investigation and all exhibits to the transcript;

v. ~~(E)~~ all other Documents obtained from the Respondent; and

vi. ~~(F)~~ all other Documents obtained from persons not employed by ~~NERC~~the CEA.

The sole ~~bases pursuant to~~grounds on which Staff ~~shall be~~is authorized to withhold Documents from inspection and copying ~~shall be~~are the bases set forth in ~~Paragraph~~Section 1.5.7(b); provided, however, that the Documents made available for inspection and copying need not include (i) exact copies of Documents the Respondent previously provided to Staff, and (ii) any Documents provided to the Respondent with or as part of the Notice of Alleged Violation, Notice of Penalty, assessment of proposed Mitigation Plan or Mitigating Activities or Remedial Action Directive.

(2) ~~(2)~~ Where there are Participants in a proceeding in addition to a single Respondent and ~~Compliance~~ Staff, the Hearing Officer or Hearing Panel shall oversee the Staff's designation of Documents to be produced to such other Participants and the development, execution and enforcement of any protective order deemed necessary.

(3) ~~(3)~~ Staff shall promptly inform the Hearing Officer and each other ~~Respondent~~Participant if, after the issuance of a notice of hearing, requests for information are issued by Staff related to the same compliance monitoring process(es) that led to the institution of the proceeding. If Staff receives Documents pursuant to a request for information after Staff has made Documents ~~have been made~~ available ~~to a Respondent~~ for inspection and copying as set forth in ~~Subparagraph~~subsection (a)(1), the additional Documents shall be made available to the ~~Respondent~~Participants not later than fourteen (14) ~~calendar~~ days after Staff receives such

Documents. If a date for the evidentiary hearing has been scheduled, Staff shall make the additional Documents available to the ~~Respondent~~other Participants not less than ten (10) ~~calendar~~ days before the ~~hearing.~~ evidentiary hearing~~evidentiary Hearing.~~ If Staff receives such Documents ten or fewer ~~calendar~~ days before the evidentiary hearing is scheduled to begin or after the evidentiary hearing begins, Staff shall make the additional Documents available immediately to the ~~Respondent.~~other Participants.

(1) ~~(3)~~ Nothing in ~~subparagraph~~subsection (a)(1) shall limit the discretion of ~~NERC~~the CCC to make any other Document available to the ~~Respondent~~Participants or the authority of the Hearing Officer to order the production of any other Documents or information by any Participant.

(b) ~~b)~~ **Documents That May Be Withheld by Staff**

(1) ~~(1)~~ Staff may withhold a Document from inspection and copying by ~~the Respondent~~a Participant if:[1]

i. ~~(A)~~ the Document is privileged to ~~Staff~~the CEA or constitutes attorney work product of ~~Staff's~~ counsel for the CEA (in applying this provision, the attorney-client privilege shall be recognized as absolute and any demand for production of attorney work product shall be granted only after a showing of substantial need by the Respondent or other Participant);

ii. ~~(B)~~ the Document is an examination or inspection report, an internal memorandum, or other note or writing prepared by a Staff member that ~~shall~~will not be offered in evidence or otherwise relied on by Staff in the hearing;

iii. ~~(C)~~ the Document would disclose ~~(i)~~:

(1) an examination, investigatory or enforcement technique or guideline ~~of NERC~~not otherwise made public of the CEA, a federal, state, or foreign regulatory authority, or a self-regulatory organization;

(2) ~~(ii)~~ the identity of a source, including a federal, state, or foreign regulatory authority or a self-regulatory organization, that furnished information or was furnished information on a confidential basis regarding an investigation, an examination, an enforcement proceeding, or any other type of civil or criminal enforcement action;

(3) or ~~(iii)~~ an examination, an investigation, an enforcement proceeding, or any other type of civil or criminal enforcement action under consideration by, or initiated by, the ~~NERC~~CEA, a federal, state, or foreign regulatory authority, or a self-regulatory organization; or

iv. ~~(D)~~ the Hearing Officer grants leave to withhold a Document or category of Documents as not relevant to the subject matter of the proceeding, or for other good cause shown.

Provided, that where a Document contains information of the type listed in ~~Subparagraphs (A), (B), (C~~subsections (i), (ii), (iii) or (~~D~~iv) that is capable of being redacted, Staff shall make the Document available for inspection and copying by ~~Respondent~~the other Participants in redacted form.

~~(2) Nothing in Subparagraph (b)(1)(B), (C), or (D) authorizes Staff to withhold a Document, or a part thereof, that contains exculpatory evidence. Nothing in Subparagraph (b)(1) requires Staff to withhold a Document from disclosure.~~

(c) ~~c)~~ **Withheld Document List:** At the time it is required to make Documents available for inspection and copying, Staff shall also provide to the Hearing Officer, the Respondent and any other Participant to which

[1] Nothing in these subsections authorizes Staff to withhold a Document, or a part thereof, that contains exculpatory evidence. Nothing in these subsections requires Staff to withhold a Document from disclosure.

Documents are being made available, a list of Documents withheld by Staff pursuant to ~~Subparagraph (b)(1).~~ those elements listed above, with a statement of the grounds that support withholding the Document. Upon review, for good cause shown, the Hearing Officer may order Staff to make any Document withheld, other than a Document that is subject to the attorney-client privilege, available to the ~~Respondent(s)~~other Participants for inspection and copying.

(d) ~~d)~~ **Timing of Inspection and Copying:** Except as set forth in this ~~Paragraph~~Section, the Hearing Officer shall determine the schedule of production of Documents for inspection and copying, provided that the Hearing Officer may modify any ~~time~~ period for production set forth in this ~~Paragraph~~Section as warranted by the circumstances.

(e) ~~e)~~ **Place and Time of Inspection and Copying:** Documents subject to inspection and copying pursuant to this ~~Paragraph~~Section shall be made available to the Respondent and other Participants for inspection and copying at the ~~NERC~~CEA office where the Documents are ordinarily maintained, or at such other office as the Hearing Officer, in his or her discretion, shall designate, or as the Participants otherwise agree. A ~~Respondent~~Participant shall be given access to the Documents at ~~NERC's~~the CEA's offices during normal business hours. A ~~Respondent~~Participant shall not be given custody of the Documents or be permitted to remove the Documents from ~~NERC's~~the CEA's offices~~.~~, other than copies of Documents made available by the CEA for that purpose.

(f) ~~f)~~ **Copying Costs:** A ~~Respondent~~Participant may obtain a photocopy of all Documents made available for inspection. A ~~Respondent~~Participant shall be responsible for the cost of photocopying. Unless otherwise ordered by the Hearing Officer, charges for copies made at the request of a ~~Respondent~~Participant shall be at a rate to be established by ~~NERC~~the CEA.

(g) ~~g)~~ **Failure to Make Documents Available —** Harmless Error: In the event that a Document required to be made available to a ~~Respondent~~Participant pursuant to this ~~Paragraph~~Section is not made available by Staff, no rehearing or amended decision of a proceeding already heard or decided shall be required where the failure to make the Document available was harmless error. Should a dispute arise as to whether a rehearing or amended decision is required due to the failure of Staff to produce a Document, the burden shall be on Staff to show that such failure was harmless error. The Hearing Officer, or, upon review, the Hearing Panel shall determine whether the failure to make the Document available was harmless error.

1.5.8 Other Discovery Procedures

(a) In addition to the production of Documents by Staff for inspection and copying by Respondent and other Participants pursuant to ~~Paragraph~~Section 1.5.7, the Participants shall be entitled to utilize all other discovery methods provided for in Rules 402 through 409 of the FERC Rules of Practice and Procedure, 18 C.F.R. § 385.402 through 385.409, including data requests, written interrogatories and requests for production of Documents or things, depositions by oral examination, requests for inspection of Documents and other property, requests for admissions, and requests for issuance of orders to one or more Registered Entities to produce Documents for inspection and copying or at the hearing or to provide testimony by an authorized representative in deposition or at the hearing.

(b) Unless otherwise directed by the Hearing Officer or Hearing Panel upon motion by a Participant, or by the Hearing Officer, or by the Hearing Panel on its own motion, such discovery, and the resolution of any disputes concerning such discovery, shall be conducted in accordance with the provisions of Rules 402 through 410 and 510(e) of the FERC Rules of Practice and Procedure, 18 C.F.R. ~~§~~§§ 385.402 through 385.410 and 385.510(e), which are hereby incorporated by reference into these Hearing Procedures, subject to the following limitations and modifications to such Rules:

(1) ~~a)~~ The provisions of ~~Subparagraphs~~subsections (d), (e) and (f) of ~~Paragraph~~Section 1.5.7 shall apply to any such discovery.

~~(2) b)~~ Rule 403(b)(2) (18 C.F.R. § 385.403(b)(2)) and Rule 410(d)(2) (18 C.F.R. § 385.410(~~b~~d)(2)) shall not be applicable.

~~(3) c)~~ The Hearing Officer and the Hearing Panel have the authority to issue orders to compel the appearance by or production of Documents or information by, only ~~any~~a Person that (i) is a Participant~~,~~ or (ii) is a Registered Entity (including an authorized representative thereof) that is not a Participant. The Hearing Officer and the Hearing Panel do not have authority to require a United States marshal or deputy marshal to serve an order to produce or provide Documents, information or testimony.

~~(4) d)~~ References to "subpoena" in Rules 404, 409, 410 and 510(e) shall be deemed to be to an order to a non-Participant Registered Entity to produce or provide Documents, information or testimony.

~~(1)~~(5) ~~e)~~ References to the "Commission" in Rules 402 through 410 and 510(e) shall be to FERC except as follows:

i. ~~(i)~~ the references in Rules 402(a), 404(b)(1) and 405(b), the second reference in Rule 410(d), and the references in Rule 510(e)(1) and (2) shall be deemed to be to the Hearing Panel~~, (ii) the reference in Rule 385.406(b)(4) to "Commission trial staff" shall be deemed to be to Compliance Staff, and (iii)~~ . ~~the reference in Rule 510(e)(3) shall be deemed to be to the Hearing Officer or Hearing Panel.~~

ii. the reference in Rule 385.406(b)(4) to "Commission trial staff" shall be deemed to be to Staff, and

~~i.~~iii. the reference in Rule 510(e)(3) shall be deemed to be to the Hearing Officer or Hearing Panel.

~~(6) f)~~ Unless otherwise ordered by the Hearing Officer or Hearing Panel, a data request, set of interrogatories, request for production of Documents or things, request for inspection of Documents or other property, request for admissions, or order to produce or provide Documents, information~~,~~ or testimony, shall not specify a due date or response date that is fewer than 21 ~~calendar~~ days from the date of service of the request or date of the order.

~~(7) g)~~ A list of withheld Documents, if any, shall be provided by any Participant required to produce Documents, at the time the Documents are required to be produced, to the Hearing Officer and to each Participant entitled to receive production of the Documents. Upon review, for good cause shown, the Hearing Officer may order the Participant to make any Document withheld available to any other Participant or Participants for inspection and copying.

~~(8) h)~~ In the event a Document or information required to be produced or provided by a Participant pursuant to discovery is not produced or provided by the Participant, no rehearing or amended decision of a proceeding already heard or decided shall be required where the failure to produce or provide the Document or information was harmless error. Should a dispute arise as to whether a rehearing or amended decision is required due to the failure of a Participant to produce or provide a Document or information, the burden shall be on the Participant that failed to produce or provide the Document or information to show that such failure was harmless error. The Hearing Officer or, upon review, the Hearing Panel shall determine whether the failure to make the Document available was harmless error.

~~(9) i)~~ Unless otherwise ordered by the Hearing Officer or Hearing Panel, all such discovery shall be requested, scheduled and conducted so as to be completed within six (6) months following the date ~~of the initial prehearing conference held pursuant to Paragraphs 1.4.1 and 1.5.2.~~the request for hearing was filed.

(10) ~~j)~~ Notwithstanding ~~(f~~subsections (b) (6) and (~~i~~b) (9), however, if the shortened hearing procedure in ~~Paragraph~~Section 1.3.~~2~~4 is used in a proceeding, the Hearing Officer, on his or her own motion or on motion of a Participant, shall establish a schedule for discovery, including response periods for responding to discovery requests, that are consistent with the expedited nature of the proceeding contemplated by the shortened hearing procedure.

~~(b)~~(c) The Hearing Officer's ruling on all motions relating to disputes concerning such discovery shall consider the following objectives:

(1) ~~(i)~~ full disclosure of all relevant Documents and information; and

(2) ~~(ii)~~ the exercise of due diligence in the conduct of discovery by a Participant; and ~~(iii)~~ disallowing use of discovery as a means to delay the proceeding or to harass or burden any other Participant.

1.5.9 Pre-Evidentiary Hearing Submission of Testimony and Evidence

(a) Unless the Hearing Officer orders otherwise and with the exception of (i) any adverse Participant examination pursuant to ~~Paragraph~~Section 1.6.16 and (ii) the testimony and documents of a non- Participant provided pursuant to an order to produce or provide Documents, information or testimony, all witness direct testimony to be submitted in ~~a~~an evidentiary hearing must be prepared in written form, may have exhibits, schedules and attachments thereto, and shall be filed in advance of the evidentiary hearing pursuant to a schedule determined by the Hearing Officer, as it may be amended. Where a Participant intends to use a Document or other demonstrative evidence that has not been filed as part of written testimony in the conduct of cross-examination (other than Documents that are to be produced by a non-Participant at the hearing pursuant to an order to produce Documents), the Participant intending to use such Document or demonstrative evidence shall provide it to the other Participants and the Hearing Officer at least three (3) business days prior to the date at which the witness will be cross-examined at ~~the evidentiary~~a testimonial hearing~~Testimonial hearing~~.

(b) ~~Compliance~~ Staff shall file the Documents it intends to offer into evidence as its direct case, including the written testimony of its witnesses along with exhibits, schedules, and attachments thereto, first. The ~~Respondent~~Registered Entity shall file the Documents it intends to offer into evidence as its direct case, which also may be responsive to Staff's direct case, including the written testimony of its witnesses along with exhibits, schedules and attachments thereto, second. Staff shall file as its rebuttal case the Documents it intends to offer into evidence in response to the ~~Respondent's~~Registered Entity's direct case, including the written testimony of its witnesses along with exhibits, schedules, and attachments thereto, third.

(c) If appropriate due to the number and/or complexity of the issues, the Hearing Officer may allow for the ~~Respondent~~Registered Entity to submit a rebuttal case that responds to Staff's rebuttal case, in which event the Hearing Officer shall also allow Staff to submit a ~~sur~~rebuttal case that responds to the ~~Respondent's~~Registered Entity's rebuttal case.

(d) Each round of evidence shall be limited in scope to responding to the preceding round of evidence, except that the ~~Respondent's~~Registered Entity's direct case may exceed the scope of Staff's direct case if necessary for the ~~Respondent~~Registered Entity to set forth its direct case fully.

(e) The Participants shall file the Documents they intend to offer into evidence in accordance with the Hearing Officer's schedule, as it may be amended. Such filings of written testimony and other evidence in advance of the evidentiary hearing shall not entitle the Documents to be admitted into the evidentiary record. The Participants must offer their witnesses' testimony and other proposed evidence for admission into the evidentiary record during the evidentiary hearing.

(f) Any Participant who fails, without good cause shown, to comply with the Hearing Officer's schedule for the filing of written testimony and other evidence in advance of the evidentiary hearing may be limited in the

presentation of its evidence during the evidentiary hearing or have its participation in the evidentiary hearing otherwise restricted by the Hearing Officer to avoid undue prejudice and delay.

1.5.10 Protective Orders

~~(a)~~ ~~a)~~ All proceedings conducted pursuant to these Hearing Procedures, and any written testimony, exhibits, other evidence, transcripts, comments, briefs, rulings and other issuances, shall be non-public and shall be held in confidence by all Participants, except as the ERO (within the U.S., in accordance with the authorization previously granted by FERC to release information about a non-public proceeding) or FERC (in the case of U.S. related information) or another Applicable Governmental Authority (in the case of non-U.S. related information) authorizes or directs public disclosure of any portion of the record. In addition to this general proscription, at any time during a proceeding, the Hearing Officer, on his or her own motion or on the motion of any Participant or of any non-Participant ordered to produce Documents, information or testimony, may enter a protective order to designate as proprietary and protect the confidential, proprietary or trade secret nature of any data, information or studies, or any other information the public release of which may cause a security risk or harm to a Participant.

~~(a)~~(b) ~~b)~~ The following types of information will be considered entitled to protection through a protective order:

(1) ~~(i)~~ Confidential Business and Market Information, including information that is proprietary, commercially valuable, or competitively sensitive;

~~i.~~(1) ~~(ii)~~ Critical Energy Infrastructure Information;

~~ii.~~(1) ~~(iii)~~ information related to a Cyber Security Incident;

(1) ~~(iv)~~ personnel information that identifies or could be used to identify a specific individual, or that reveals personnel, financial, medical or other personal information; ~~(v) audit work papers; (vi) investigative files or documents that would disclose investigative techniques of the ERO or any federal, state or foreign regulatory authority. Nothing in this Subparagraph 1.5.10(b) shall require Staff to produce any Documents it is entitled to withhold under Subparagraph 1.5.7(b).~~

(2) ~~c)~~ audit work papers; or

(3) investigative files or Documents that would disclose investigative techniques of Staff, any CEA, the ERO or any federal, state or foreign regulatory authority.

Nothing in this subsection 1.5.10(b) shall require Staff to produce any Documents it is entitled to withhold under subsection 1.5.7(b).

(c) A motion for a protective order shall specify the proposed expiration date for the proprietary status of the data, Documents, or information, if any, and shall propose requirements or safeguards to be met for individuals participating in the proceeding to review the protected information while maintaining its proprietary status.

(d) ~~d)~~ A Document submitted and marked as proprietary, or a statement made at a hearing and identified as proprietary, shall be afforded proprietary treatment pending the timely submission of a motion to protect the confidential, proprietary or trade secret nature of that Document or statement and a ruling on such a motion by the Hearing Officer.

(e) ~~e)~~ The protective order shall identify the data, Documents, or information that will be accorded proprietary treatment; the individuals participating in the proceeding, by category or otherwise, entitled to view the proprietary information; and the requirements, conditions or safeguards that must be met before an individual may view the information.

(f) ~~f)~~ A public redacted version of each Document and transcript that contains information that is protected pursuant to this ~~Paragraph~~Section must be filed with the proprietary version and must be served on each Participant for distribution to those individuals participating in the proceeding who are not entitled to view the proprietary information.

(g) ~~g)~~ Should it be necessary to address proprietary information during a hearing, the Hearing Officer shall, while the information is being addressed, close the hearing to all individuals other than those entitled to view or hear the proprietary information in accordance with the protective order.

1.5.11 Pre-Evidentiary Hearing Memorandum

(a) The Hearing Officer or the Hearing Panel may request~~, as needed on a case by case basis due to the number or complexity of the issue(s),~~ the submission of memoranda prior to the evidentiary hearing that ~~outline~~set forth each Participant's position on the issue(s) in dispute, the key facts and arguments, ~~and~~ the applicable Reliability Standard, rules, orders or other authority~~.~~, and such other matters as may be directed by the Hearing Officer or the Hearing Panel.

(b) The purpose of such memoranda will be to aid the Hearing Officer and Hearing Panel in preparation for the evidentiary hearing. A Participant will not be deemed to have waived any issue, fact or argument that is not set forth in a pre-evidentiary hearing memorandum. ~~The Hearing Officer may establish page limitations on such submissions.~~

(c) The Hearing Officer may establish word limitations on such submissions.

1.5.12 Certification of Questions to the NERC Board of Trustees Compliance Committee

(a) Should a hearing present a significant question of law, policy or procedure the resolution of which may be determinative of the issues in the proceeding in whole or in part, and as to which there are other extraordinary circumstances that make prompt consideration of the question by the NERC Board of Trustees Compliance Committee appropriate, the Hearing Officer, on his or her own motion or on motion of a Participant, may recommend to the Hearing Panel that it certify, or the Hearing Panel on its own motion may decide to certify, the question to the Board of Trustees Compliance Committee for determination pursuant to Section 412 of the Rules of Procedure.

(b) If the Hearing Officer, on his or her own motion, or the Hearing Panel, on its own motion, wishes to present a question to the Hearing Panel for certification to the NERC Board of Trustees Compliance Committee, the Hearing Officer shall first provide the Participants the opportunity to submit memoranda addressing whether the question should be certified and the precise terms of the question to be certified.

(c) If a Participant files a motion requesting, or the Hearing Officer determines on his or her own motion, that a question should be certified to the Board of Trustees Compliance Committee, the Hearing Officer shall submit a written recommendation on the matter to the Hearing Panel. If the request for certification is based on the motion of a Participant, the Hearing Officer shall also submit to the Hearing Panel the motion and any answers to the motion that were filed. If the request for certification is on the Hearing Officer's own motion, the Hearing Officer shall also submit to the Hearing Panel the Participants' memoranda that were filed pursuant to subsection (b).

(d) Questions of fact presented by the particular matter in dispute in a hearing shall not be the subject of a certification to the Board of Trustees Compliance Committee.

(e) The Hearing Panel shall determine, based on the criteria specified in subsection (a), whether the proposed question shall be certified to the Board of Trustees Compliance Committee for determination. To certify the proposed question, the Hearing Panel must determine that the question is a significant question of law, policy

or procedure the resolution of which may be determinative of the issues in the proceeding, in whole or in part, and that there are extraordinary circumstances that make prompt consideration of the question by the Board of Trustees Compliance Committee appropriate. If the Hearing Panel determines that the proposed question should be certified to the Board of Trustees Compliance Committee, the Hearing Panel shall also determine whether the hearing should be suspended, in whole or in part, while the question is pending before the Board of Trustees for determination.

(f) As provided in Rule of Procedure Section 412, the Board of Trustees Compliance Committee may decide to reject a proposed certification from a Hearing Panel.

(g) If the Board of Trustees Compliance Committee accepts certification of a question and issues a determination on the question, the hearing shall proceed following the determination in accordance with the Board of Trustees Compliance Committee's decision.

1.6 Procedure at Evidentiary Hearing ~~Procedure~~

1.6.1 Purpose of Evidentiary Hearings

The purpose of the evidentiary hearing shall be to admit the Participants' evidence into the record, and for each Participant to have the opportunity to cross-examine the other Participant's witnesses. A schedule for briefs, unless waived by the Participants, shall be set at the conclusion of the evidentiary hearing. ~~The evidentiary hearing also may be used to address any other issue pending between the Participants.~~

1.6.2 Order of Receiving Evidence

In all proceedings ~~Compliance~~ Staff shall open and close.

1.6.3 Opening and Closing Statements

Opening and closing statements will not be made during the evidentiary hearing as a matter of course except that such statements may be allowed when requested by a Participant, and shall be required when requested by the Hearing Officer or the Hearing Panel. Any Participant's request for such statements, or a Hearing Officer or Hearing Panel notice requiring such statements, shall be made at least ten (10) ~~calendar~~ days in advance of the start of the evidentiary hearing.

1.6.4 Right of Participant to Present Evidence

Subject to compliance with the requirements of these Hearing Procedures concerning the timing of submission of written testimony and other evidence, a Participant has the right to present such evidence, to make such objections and arguments, and to conduct such cross-examination as may be necessary to assure the true and full disclosure of the facts.

1.6.5 Exhibits

(a) All material offered in evidence, except oral testimony allowed by the Hearing Officer or the testimony of a non-Participant pursuant to an order to produce or provide Documents, information or testimony, shall be offered in the form of an exhibit.

(b) Each exhibit must be marked for identification. A Participant must provide the court reporter with two (2) copies of every exhibit that the Participant offers into evidence, and will provide copies of any exhibit not served in advance of the evidentiary hearing to the Participants and the Hearing Officer.

1.6.6 Witness Attendance at ~~Evidentiary~~Testimonial Hearing

(a) Each witness shall attend the ~~**evidentiary**~~ testimonial hearing~~Testimonial hearing~~ in person unless a Participant has been informed in advance of the ~~**evidentiary**~~ testimonial hearing~~Testimonial hearing~~ that all other Participants waive cross- examination of the witness and neither the Hearing Officer nor the members of the Hearing Panel have any questions for the witness, in which event the witness does need not be present at the ~~**evidentiary hearing.**~~ testimonial hearing~~Testimonial Hearing~~.

(b) A person compelled to appear, voluntarily testifying, or making a statement may be accompanied, represented, and advised by an attorney.

(c) All testimony offered at ~~the evidentiary~~a testimonial hearing ~~Testimonial hearing~~ is to be under oath or affirmation. If a witness is not required to attend the ~~evidentiary~~ testimonial hearing~~Testimonial hearing~~, then the Participant on whose behalf the witness prepared testimony shall submit an affidavit of the witness attesting to the veracity of the witness' testimony, and the Participant shall be allowed to introduce the

witness' testimony, and the exhibits, schedules and attachments thereto, into the evidentiary record based on such affidavit.

1.6.7 Admission of Evidence

(a) ~~Compliance~~ Staff shall offer its exhibits into evidence first and the ~~Respondent~~Registered Entity second, unless the Participants agree otherwise.

(b) Except for witnesses who are not required to attend the ~~evidentiary~~ testimonial hearing~~Testimonial hearing~~, the Participants shall call each witness in turn. Following the witness' swearing in, the witness shall attest to the veracity of his or her written testimony. The witness may identify any language and/or figures in his or her written testimony or exhibits that the witness would like to change or correct. Subject to objection, such changes or corrections may be allowed at the Hearing Officer's discretion for the purpose of obtaining a full, accurate, and complete record without imposing undue delay or prejudice on any Participant. The Participant whose witness has made changes or written corrections to written testimony and exhibits shall file corrected copies with the ~~NERC Director of Compliance~~Clerk and provide corrected copies to the Hearing Officer and other Participant.

(c) Once a witness has attested to the veracity of his or her testimony, the Participant on whose behalf the witness is testifying shall move for admission of the witness' testimony, including all exhibits, schedules, and attachments thereto, into evidence. Other Participants may object to the introduction of the witness' testimony, or any part thereof, as set forth in ~~Paragraph~~Section 1.6.11. Subject to the Hearing Officer's ruling on the objection, the witness' testimony shall be admitted into evidence. The witness shall then be turned over for cross-examination by other Participants, and for any questions by the Hearing Officer or any member of the Hearing Panel, in accordance with ~~Paragraph~~Section 1.6.14, and then for redirect examination in accordance with ~~Paragraph~~Section 1.6.15. Witnesses shall be cross-examined on all previously-served testimony (direct, rebuttal or ~~surrebuttal~~sur-rebuttal) when they first take the witness stand.

(d) Except (i) in exceptional cases and upon a showing of good cause and (ii) witnesses testifying pursuant to an order to produce or provide Documents, information or testimony issued to a non-Participant, no witness shall be allowed to testify ~~during the evidentiary hearing~~ unless a Participant has served the witness' written testimony in advance of the ~~evidentiary~~ testimonial hearing~~Testimonial hearing~~ in accordance with the schedule established by the Hearing Officer. Due to the undue prejudice such surprise witness testimony would impose on other Participants, it is the CCC's policy to discourage witness testimony at ~~an evidentiary~~a testimonial hearing ~~Testimonial hearing~~ when a Participant has not served the witness' written testimony in advance of the ~~evidentiary hearing.~~ testimonial hearing~~Testimonial Hearing.~~ If such testimony is allowed, sufficient procedural steps shall be taken by the Hearing Officer to provide the other Participants with a fair opportunity for response and cross-examination.

1.6.8 Evidence that is Part of a Book, Paper or Document

(a) When relevant and material matter offered in evidence is embraced in a book, paper or Document containing other matter that is not material or relevant, the Participant offering the same must plainly designate the matter offered as evidence, and segregate and exclude the material not offered to the extent practicable.

(b) If the material not offered is in such volume as would unnecessarily encumber the record, such book, papers or Document will not be received in evidence but may be marked for identification and, if properly authenticated, the relevant or material matter may be read into the record, or, if the Hearing Officer so directs, a separate copy of such matter in proper form shall be offered as an exhibit.

(c) All other Participants shall be afforded an opportunity to examine the book, paper, or Document and to offer in evidence in like manner other portions thereof if found to be material and relevant.

1.6.9 Stipulations

The Participants may stipulate to any relevant fact or the authenticity of any relevant Document. Stipulations may be made in writing or entered orally in the record. Notwithstanding stipulation, the Hearing Officer may require evidence of the facts stipulated in order to provide a complete evidentiary record on which to base the final order.

1.6.10 Official Notice

(a) Where relevant and material to the subject matter of the proceeding, the Hearing Officer may, upon request of a Participant, take official notice of any of the following:

(1) ~~a)~~ Rules, regulations, administrative rulings, and orders, written policies of governmental bodies, and rulings and orders of ~~NERC and Regional Entities.~~ other CEAs.

(2) ~~b)~~ The orders, transcripts, exhibits, pleadings, or any other matter contained in the record of other docketed proceedings of ~~NERC.~~ the CEA.

(3) ~~c)~~ State, provincial and federal statutes and municipal and local ordinances.

(4) ~~d)~~ The decisions of state, provincial, and federal courts.

(5) ~~e)~~ Generally recognized scientific or technical facts within the specialized knowledge of the ~~NERC.~~ CEA.

(6) ~~f)~~ All other matters of which the courts of the United States may take judicial notice.

~~(a)~~(b) All requests to take official notice shall be submitted in advance of the evidentiary hearing in accordance with a schedule established by the Hearing Officer. Before ruling on a request to take official notice, the Hearing Officer shall afford the other Participant opportunity to object or to show the contrary to the matter for which official notice is requested.

(c) An accurate copy of any item officially noticed shall be introduced into the record in the form of an exhibit presented by the Participant requesting official notice unless waived by the Participants and approved by the Hearing Officer. Any information officially noticed and not presented as an exhibit shall be set forth in a statement on the record.

1.6.11 Admissibility of Evidence

(a) Any evidence offered, including that included in a book, paper, or Document pursuant to ~~Paragraph~~Section 1.6.8, shall be subject to appropriate and timely objections. Any Participant objecting to the admission or exclusion of evidence must state the grounds for objection.

(b) The admission of evidence shall not be limited by the generally recognized rules of evidence as applied in the courts of the United States or of the states, although the Hearing Officer may take such rules of evidence into consideration in ruling on the admissibility of evidence. The Hearing Officer will exercise discretion in the admission of evidence based upon arguments advanced by the Participants, and shall admit evidence if it is of a type commonly relied upon by reasonably prudent persons in the conduct of their affairs. The Hearing Officer may only exclude material from the record in response to a motion or objection by a Participant.

(c) Formal exception to a ruling on admissibility of evidence need not be taken to be preserved.

1.6.12 Offer of Proof

Any Participant who has had evidence excluded may make an offer of proof on the record. The offer of proof may consist of a statement made on the record of the substance of the evidence that the Participant claims would have

been adduced, or any written or documentary exhibit that the Participant sought to introduce. Any such exhibit shall be retained as part of the record.

1.6.13 Reservation of Evidentiary Ruling

(a) The Hearing Officer shall rule upon any objection to the admissibility of evidence at the time the objection is made; provided that the Hearing Officer has discretion to reserve such a ruling or to require the Participants to file written arguments in relation thereto.

(a) If the Hearing Officer reserves the ruling, appropriate steps shall be taken during the evidentiary hearing to ensure a full, complete, and accurate record in relation to the objected to evidence in the event the objection to the evidence's admissibility is overruled.

1.6.14 Cross-Examination

(a) Each witness shall be tendered for cross-examination subsequent to the admission of the witness' testimony into the evidentiary record. Each Participant shall have the right to cross-examine each witness of any other Participants. A Participant may waive cross-examination of any witness. Leading questions are permitted on cross-examination.

(b) The credibility of a witness may be attacked by any Participant, including the Participant calling the witness.

(c) The Hearing Officer and any member of the Hearing Panel may ask the witness questions following the conclusion of the witness' cross-examination by the other Participant, and prior to the witness' redirect examination pursuant to ~~Paragraph 1.6.15. If a member of the Hearing Panel seeks to ask a witness questions, the member shall do so by submitting the question in writing to the Hearing Officer, and the Hearing Officer shall ask the question of the witness~~Section 1.6.15.

1.6.15 Redirect Examination

A Participant shall be entitled to conduct redirect examination of each of the Participant's witnesses who are subject to cross-examination or questions of the Hearing Officer or a member of the Hearing Panel. Any redirect examination shall be limited in scope to the witness' cross- examination and questions of the Hearing Officer and members of the Hearing Panel~~. If a member of the Hearing Panel seeks to ask a witness questions, the member shall do so by submitting the question in written form to the Hearing Officer, and the Hearing Officer shall ask the question of the witness~~.

1.6.16 Examination of Adverse Participant

(a) Any Participant may call any adverse Participant, or any employee or agent thereof, during the ~~evidentiary~~ testimonial hearing~~Testimonial hearing~~ to provide oral testimony on the Participant's behalf, and may conduct such oral examination as though the witness were under cross-examination.

(a) If a Participant intends to call an adverse Participant for examination, it shall give notice to the Hearing Officer and all other Participants setting forth the grounds for such examination at least fourteen (14) ~~calendar~~ days in advance of the ~~evidentiary~~ testimonial hearing~~Testimonial hearing~~, and the Participant who, or whose employee or agent, is sought to be called shall file any objection at least seven (7) ~~calendar~~ days in advance of the ~~evidentiary hearing.~~ testimonial hearing~~Testimonial Hearing~~

(b) Any Participant may conduct oral examination of a witness testifying pursuant to an order to produce or provide Documents, information or testimony issued to a non-Participant, as though the witness were under cross-examination.

1.6.17 Close of the Evidentiary Record

(a) The Hearing Officer shall designate the time at which the evidentiary record will be closed, which will typically be at the conclusion of the evidentiary hearing. ~~Evidence may not be added to the evidentiary record after it is closed, provided that the Hearing Officer may reopen the evidentiary record for good cause shown by any Participant.~~

(b) Evidence may not be added to the evidentiary record after it is closed, provided that, prior to issuance of the Hearing Panel's final order, the Hearing Officer may reopen the evidentiary record for good cause shown by any Participant. For the purpose of reopening the evidentiary record, newly discovered evidence that is material to the issues in dispute and could not, by due diligence, have been discovered prior to or during the evidentiary hearing~~Evidentiary Hearing~~, shall constitute good cause.

1.7 Post- Evidentiary Hearing Procedure

1.7.1 Briefs

(a) ~~a)~~ At the close of the evidentiary hearing, Participants may file initial and reply briefs.

(b) ~~b)~~ Briefs shall be concise, and, if in excess of twenty (20) pages, excluding appendices, shall contain a table of contents. Statements of fact should be supported by record citations.

(c) ~~c)~~ The Hearing Officer will prescribe the time for filing briefs, giving due regard to the nature of the proceeding, the extent of the record, the number and complexity of the issues, and the objective of expedition.

(d) ~~d)~~ Unless the Hearing Officer prescribes otherwise, all Participants shall file initial and reply briefs simultaneously.

(e) ~~e)~~ Participants' reply briefs shall be limited in scope to responding to arguments and issues raised in other Participants' initial briefs.

(f) ~~f)~~ The Hearing Officer may~~, with the agreement of the Participants,~~ allow oral closing statements to be made on the record in lieu of briefs.

(g) ~~g)~~ The Hearing Officer may establish reasonable ~~page~~word limitations applicable to briefs.

1.7.2 Other Pleadings

Post-hearing pleadings other than briefs are permitted, but, absent good cause shown, such pleadings may not seek to introduce additional evidence into the record.

1.7.3 Draft Initial Opinions

The Hearing Officer may permit or require Participants to file draft initial opinions that set forth the Participants' proposed findings of fact and conclusions.

1.7.4 Hearing Officer's Initial Opinion

(a) ~~Except as otherwise ordered by the Hearing Panel, at~~At the conclusion of the evidentiary hearing, and following the submission of initial and reply briefs and draft orders, if any, the Hearing Officer shall prepare an initial opinion for the Hearing Panel's review and consideration.

(a) The initial opinion shall include a statement of each finding and conclusion, and the reasons or basis therefore, for all material issues ~~of fact, law or discretion~~ presented on the record. The initial opinion also shall contain the appropriate orders to dispose of the proceeding, including any Penalty, Mitigation Plan or Mitigating Activities, or Remedial Action Directive that the Hearing Officer proposes the Hearing Panel require.

(b) ~~If the initial opinion proposes a Penalty, the initial opinion shall include a proposed Notice of Penalty.~~ The initial opinion shall note if the subject of the proceeding has been deemed to involve a Cyber Security Incident, if any information in the proceeding was deemed to be Critical Energy Infrastructure Information, or if any information in the proceeding is the subject of a protective order pursuant to ~~Paragraph~~Section 1.5.10.

1.7.5 Exceptions

(a) ~~a)~~ Within twenty-one (21) ~~calendar~~ days after service of the initial opinion, or such other time as is fixed by the Hearing Officer, any Participant may file exceptions to the initial opinion in a brief designated "brief on exceptions" and, within fourteen (14) ~~calendar~~ days after the time for filing briefs on exceptions or such other time as is set by the Hearing Officer, any Participant may file as a reply, a "brief in reply to exceptions."

(b) ~~b)~~ Exceptions and replies thereto with respect to statements, findings of fact or conclusion in the initial opinion must be specific and must be stated and numbered separately in the brief. With regard to each exception, the Participant must specify each error asserted, and include a concise discussion of any policy considerations applicable and any other evidence and arguments in support of the Participant's position. Suggested replacement language for all statements to which exception is taken must be provided. Exceptions and arguments may be filed (1) together in one brief; or (2) in two separate documents, one designated as the brief containing arguments, and the other designated "Exceptions," containing the suggested replacement language.

(c) ~~c)~~ Arguments in briefs on exceptions and replies thereto shall be concise and, if in excess of twenty (20) pages, shall contain a table of contents.

(d) ~~d)~~ Participants shall not raise arguments in their briefs in reply to exceptions that are not responsive to any argument raised in any other Participant's brief on exceptions.

(e) ~~e)~~ Statements of fact should be supported by citation to the record.

(f) ~~f)~~ The Hearing Officer may establish reasonable ~~page~~word limitations applicable to arguments included in briefs on exception and briefs in reply to exceptions. Such ~~page~~word limitations shall not apply to a Participant's proposed replacement language.

(g) ~~g)~~ Unless good cause is shown, if a Participant does not file a brief on exceptions, or if a Participant filed a brief on exceptions that does not object to a part of the initial opinion, the Participant shall be deemed to have waived any objection to the initial opinion in its entirety, or to the part of the initial opinion to which the Participant did not object, whichever applies. This provision shall not prohibit the Participant, in its brief in reply to exceptions, from responding to another Participant's exceptions to such part of the initial opinion or from proposing alternative replacement language to the replacement language proposed by the other Participant for such part of the initial opinion.

1.7.6 Oral Argument

(a) The Hearing Panel may elect to hear oral argument. If oral argument is held without briefs having been filed, Participants will be given the opportunity to present argument on all issues.

(b) If oral argument is held where briefs have been filed, argument may be limited to issues identified by the Hearing Panel. The Hearing Panel will direct the ~~NERC Director of Compliance~~Clerk to issue a notice of oral argument that identifies the date, time, place and issues for the argument.

(c) The presentation of written materials or visual aids is permitted at oral argument. To the extent such materials or aids contain factual information, they shall be supported by the record, and ~~shall~~ contain accurate ~~record~~ citations~~.~~ to the record. Such materials or aids may not contain new calculations or quantitative analyses not presented in the record, unless they are based on underlying data contained in the record. Copies of all written materials or visual aids to be presented at oral argument shall be served on all Participants not less than forty-eight (48) hours prior to the time and date of oral argument.

1.7.7 Additional Hearings

After the evidentiary record has been closed but before issuance of ~~an initial opinion~~the Hearing Panel's final order, the Hearing Officer may reopen the evidentiary record and hold additional hearings. Such action may be taken on the Hearing Officer's or the Hearing Panel's own motion if there is reason to believe that reopening is warranted by any changes in conditions, or by the need to compile a complete evidentiary record on which to base the final order. Any Participant may file a motion to reopen the record, which shall contain the reasons for reopening, including material changes in conditions or the identification of additional evidence that should be included in the record, and a brief statement of proposed additional evidence and an explanation why such evidence was not previously ~~adduced.~~ cited as evidence.

1.7.8 Hearing Panel Final Order

(a) Following the receipt of the initial opinion, any exceptions, and replies thereto, and oral argument, if any, the Hearing Panel shall issue its final order.

(b) Issuance of a final order shall require (i) a quorum of the Hearing Panel, which shall be (after any recusals, disqualifications and appointments of replacement members) at least fifty (50) percent of the number of members normally assigned to the Hearing Panel, and (ii) majority vote of the members of the Hearing Panel voting on the final order ~~(which~~(in which the number of members voting shall not be less than a quorum).

(c) The Hearing Panel shall ~~strive, but shall not be required, to~~ issue its final order within thirty (30) ~~calendar~~ days following the last to occur of the initial opinion, exceptions, ~~or~~ replies thereto, or oral argument. The Hearing Panel may extend this deadline for good cause and shall provide written notice of any extension to all Participants. The final order may adopt, modify, amend, or reject the initial opinion in its entirety or in part. The final order shall include a statement of each finding and conclusion, and the reasons or basis therefore, for all material issues ~~of fact, law or discretion~~ presented on the record.

(d) The Hearing Panel will base its determinations in the final order on the record. The final order also shall contain the appropriate orders to dispose of the proceeding, including any Penalty, ~~sanction,~~ Remedial Action Directive ~~or~~, Mitigation Plan or Mitigating Activities required.

(e) ~~If the final order imposes a Penalty, it shall be entitled "Final Order and Notice of Penalty".~~ The final order shall note if the subject of the proceeding has been deemed to involve a Cyber Security Incident, if any information in the proceeding was deemed to be Critical Energy Infrastructure Information, or if any information in the proceeding is the subject of a protective order issued pursuant to ~~Paragraph 1.5.10. The Hearing Panel shall direct the NERC Director of Compliance to serve the final order on the Participants.~~ Section 1.5.10.

(f) The service of the final order shall include a notice informing the Participants of their appeal rights ~~pursuant~~ to ~~Section 400 of~~ the ~~Rules of Procedure.~~ ERO or to FERC, as applicable.

1.7.9 The Record

(a) The ~~NERC Director of Compliance~~Clerk shall maintain the record for all dockets. The record shall include any of the following, including all attachments thereto and Documents filed therewith, that exist in any docket:

(1) ~~a)~~ Notice of Alleged Violation and ~~Respondent's~~Registered Entity's response thereto;

(2) ~~b) Respondent's~~Registered eEntity's proposed Mitigation Plan or Mitigating Activities and Staff's statement identifying its disagreement(s) therewith;

(3) ~~c)~~ Remedial Action Directives and the ~~Respondent's~~Registered Entity's notice contesting the Remedial Action Directive;

(4) ~~d) Respondent's~~Registered eEntity's request for a hearing;

(5) ~~e)~~ Participant filings, motions, and responses;

(6) ~~f)~~ Notices, rulings, orders and other issuances of the Hearing Officer and Hearing Panel;

(7) ~~g)~~ Transcripts;

(8) ~~h)~~ Evidence received;

(9) ~~i)~~ Written comments submitted in lieu of written testimony;

(10) ~~j)~~ Matters officially noticed;

(11) ~~k)~~ Offers of proof, objections and rulings thereon, and any written or documentary evidence excluded from the evidentiary record;

(12) ~~l)~~ ~~**Briefs, pre**~~Pre-evidentiary hearing memorandums, briefs, and draft opinions;

(13) ~~m)~~ Post-hearing pleadings other than briefs;

(14) ~~n)~~ The Hearing Officer's initial opinion;

(15) ~~o)~~ Exceptions to the Hearing Officer's initial opinion, and any replies thereto;

(16) ~~p)~~ The Hearing Panel's final order~~**, any Notice of Penalty issued therewith,**~~ and the ~~**NERC Director of Compliance's**~~Clerk's notice transmitting the final order to the Participants;

(17) ~~q)~~ All notices of ex parte communications; and

(18) ~~r)~~ Any notifications of recusal and motions for disqualification of a member of the Hearing Panel or Hearing Officer or Technical Advisor and any responses or replies thereto.

1.7.10 Appeal

~~A~~A Participant or a Regional Entity acting as the CEA, may appeal a final order of the Hearing Panel ~~may be appealed~~ to NERC in accordance with ~~NERC's Rules~~Rules of Procedure~~,~~ S~~ubs~~ection~~s~~ 409.~~5 et seq.~~

1.8 Settlement

Settlements may be entered into at any time pursuant to Section 5.~~4~~6 of the NERC Compliance Monitoring and Enforcement Program and ~~NERC's~~the CEA's settlement procedures, provided, that (i) the CEA may decline to engage in or continue settlement negotiations after a Possible Violation or Alleged Violation becomes a Confirmed Violation, and (ii) the CEA, the Registered Entity or any other Participant may terminate settlement negotiations at any time.

1.9 Remedial Action Directives

1.9.1 Initiation of Remedial Action Directive Hearing

(a) Staff may issue a Remedial Action Directive to a ~~Respondent~~Registered Entity at any time, including during any proceeding related to an Alleged Violation of a Reliability Standard. The Remedial Action Directive shall be delivered to the ~~Respondent~~Registered Entity in accordance with Section 7.0 of the NERC Compliance Monitoring and Enforcement Program.

(b) The ~~Respondent~~Registered Entity may contest the Remedial Action Directive by filing a written notice with the NERC Director of ~~Compliance~~Enforcement that states that the ~~Respondent~~Registered Entity contests the Remedial Action Directive and that the ~~Respondent~~Registered Entity requests a Remedial Action Directive hearing. The ~~Respondent~~Registered Entity shall attach a copy of the Remedial Action Directive to its written notice. The ~~Respondent~~Registered Entity must provide such notice within two (2) business days following the date of actual receipt (as defined in Section 7.0 of the NERC Compliance Monitoring and Enforcement Program) of the Remedial Action Directive. If the ~~Respondent~~Registered Entity does not give written notice ~~to the NERC Director of Compliance~~ within the required ~~time~~ period, the ~~Respondent~~Registered Entity shall be deemed to have waived its right to contest the Remedial Action Directive.

(c) The ~~NERC Director of Compliance~~Clerk shall assign a docket number, and issue a notice of hearing that sets forth the date, time, and place at which the hearing will convene ~~pursuant to Paragraph 1.4.1~~.

1.9.2 Remedial Action Directive Hearing Procedure

(a) Hearings to address Remedial Action Directives shall be conducted only under the expedited hearing process set forth in this ~~Paragraph~~Section~~n 1.9.2~~. The ~~full~~general hearing procedures described in ~~Paragraphs~~Sections 1.4 to 1.7 are applicable to the Remedial Action Directive hearing unless the context of a provision is inconsistent with or otherwise renders it inapplicable to the procedures set forth in this ~~Paragraph.~~ Section.

(b) The Remedial Action Directive hearing ~~may~~shall be presided over by a Hearing Officer and will be conducted according to the following guidelines:

~~a)~~(1) The Hearing Officer or the Hearing Panel will hold a prehearing conference within two (2) ~~b~~bB~~b~~usiness days after receipt of the ~~Respondent's~~Registered Entity's request for a hearing.

~~b)~~(1) ~~An evidentiary~~A testimonial hearing ~~Testimonial hearing~~ will be conducted on the matter, in person or by teleconference, within seven (7) business days after the prehearing conference.

~~c)~~(1) At the ~~evidentiary~~ testimonial hearing~~Testimonial hearing~~, Staff shall present oral witness testimony and evidence to show why the Remedial Action Directive should be complied with, and the ~~Respondent~~Registered Entity shall present oral witness testimony and evidence to show why the Remedial Action Directive is not necessary or should be modified. All witness testimony shall be rendered under oath.

~~d)~~(1) At the ~~evidentiary~~ testimonial hearing~~Testimonial hearing~~, the Participants shall have the opportunity to make opening statements. In addition, the Participants shall have the opportunity to make closing arguments, and Staff shall have the opportunity to make a rebuttal to the ~~Respondent's~~Registered Entity's closing argument.

~~e)~~(1) The Participants may file initial briefs and reply briefs, and/or draft opinions, on an expedited schedule set by the Hearing Officer or the Hearing Panel. Oral argument shall not be held.

~~f)~~(c) The Hearing Panel shall issue a summary written decision within ten (10) ~~calendar~~ days following submission of the ~~hearing~~last brief, stating whether the ~~Respondent~~Registered Entity shall or shall not be

required to comply with the Remedial Action Directive and identifying any modifications to the Remedial Action Directive that ~~it~~ the Hearing Panel finds appropriate. Upon issuance of the summary written decision, the Registered Entity is required to comply with the Remedial Action Directive as specified in the summary written decision.

(d) Within thirty (30) ~~calendar~~ days following issuance of its summary written decision, the Hearing Panel shall issue a full written decision. The written decision shall state the conclusions of the Hearing Panel with respect to the Remedial Action Directive, and shall explain the reasons for the Hearing Panel's conclusions.

Exhibit B

Proposed NERC Rules of Procedure Appendix 4E

CCCPP-006-2 Mediation Procedures – Clean and Redline Versions

CCCPP-006-2 Mediation Procedures – Clean

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Compliance and Certification Committee Mediation Procedures

CCC Monitoring Program – CCCPP-006-2
Effective: [proposed date] Version 2.0

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TABLE OF CONTENTS

Preface i

Introduction ii

Chapter 1: Mediators 1

Chapter 2: Mediation Process 2

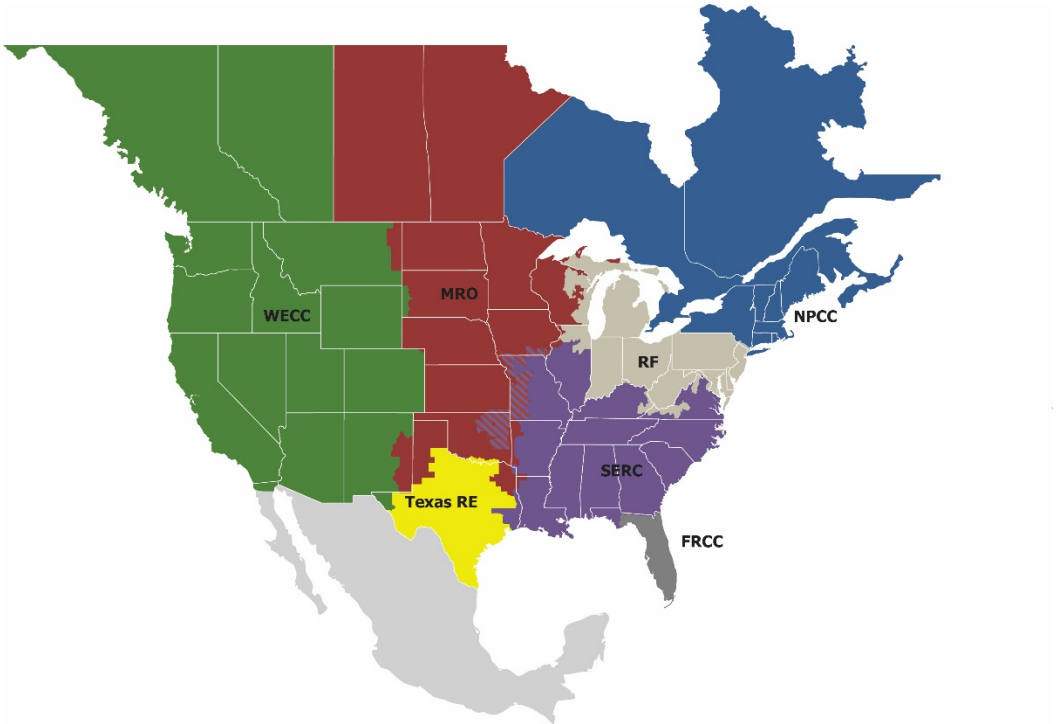
- Introductory Remarks 2
- Statements of the Issue (s) by the Parties 3
- Information Gathering 3
- Issue Identification 3
- Determination and Discussion of Options 3
- Written Mediation Settlement Agreement 3

Chapter 3: Revision History 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, 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 Regional Entity 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

The NERC Compliance and Certification Committee (CCC) Mediation Program is designed as an informal, voluntary process in which a CCC mediation panel assists NERC and a Regional Entity (NERC and the Regional Entity individually a Party, collectively, the Parties) to understand and work through disagreements or disputes concerning NERC performance audits of a Regional Entity's Compliance Monitoring and Enforcement Program. Mediation is the intervention into a dispute or negotiation of an acceptable, impartial, and neutral third party panel that has no decision-making authority. The objective of the neutral third-party is to assist the Parties in voluntarily reaching an acceptable resolution of the issues in dispute. The mediation process is voluntary and does not eliminate other dispute resolution options. Also, the mediation process is confidential, whether or not it results in settlement.

This alternative dispute resolution mechanism is intended to be a more collaborative, less adversarial method to attain a mutually agreeable resolution to the dispute, consistent with the NERC Rules of Procedure and without formal hearing proceedings.

The Parties in mediation are not obligated to reach agreement. If they do not reach a consensus, either Party may elect to proceed with other more "traditional" methods of resolving the dispute. In those instances where consensus is reached and memorialized in a written Mediation Settlement Agreement, the agreements of the Parties as expressed therein will be binding and enforceable.

Chapter 1: Mediators

The program follows a model of team mediation, having three mediators facilitate the mediation, in order to ensure a broad spectrum of perspectives and approaches to problem solving.

Once NERC and a Regional Entity have decided to pursue a resolution of their dispute through mediation, each Party will provide the chair of the CCC with introductory information (*i.e.*, brief statements of the nature and history of the dispute, participants' names, and contact information). Each Party must be represented by participants who will have the authority to enter into an agreement to resolve the matter in dispute, if the Parties are able to reach an agreement. The chair then provides the introductory information to three impartial and independent third party neutral members of the CCC to whom the chair assigns to serve as mediators and who are acceptable to both Parties. Subject to the consent of both Parties, the chair may appoint in addition to the CCC members a disinterested professional mediator who is acceptable to both Parties, with the cost of the professional mediator shared equally between the Parties. The mediators may choose, but are not required, to select one of their number as the Lead Mediator to coordinate the process and serve as their primary contact with the Parties; if a professional mediator is appointed by the chair, then that person will serve as the Lead Mediator. After reviewing the information provided by the Parties, the Lead Mediator, if any, or the mediators will communicate with the Parties to arrange an agreeable time and location for the mediation to be held.

Mediation is an informal process and is only successful when a mutually agreeable resolution occurs; however there is no single correct procedure required for mediators to follow. In any specific matter, one or more mediators may elect to discuss individual issues and concerns with one or more of the Parties prior to the session, or one or more mediators may elect to wait until the mediation session to hold any discussion. Both approaches are acceptable.

The materials provided as introductory information and all communications made during or in connection with mediation will be kept confidential by the mediators and both Parties. Statements made by the Parties during mediation may not be used against them in later proceedings. The sole exception to this rule of confidentiality would be any written Mediation Settlement Agreement entered into by the Parties, as discussed below. Should the mediation be unsuccessful, no one who participated as a mediator will serve in any capacity in connection with any subsequent legal, regulatory, administrative, or grievance proceeding regarding the subject of the mediation.

Mediators will not provide legal advice or counsel. Mediators also may not be called to testify in any legal, regulatory, administrative, or grievance proceedings concerning the mediation or its subject, nor may they be requested to provide documentation, records, *etc.*, concerning the mediation.

Once the mediation process begins, Parties may discuss their interests and concerns with the mediators (and particularly with the Lead Mediator, if any) at any time.

Chapter 2: Mediation Process

Mediators will focus on helping the Parties clearly identify their basic concerns and issues, and use this information to develop a mutually agreeable resolution. To succeed, this approach must encourage and require open communication, cooperation, and participation.

Although no single process needs to apply to all mediations, generally a successful mediation will involve six elements:

- Introductory remarks;
- Statements of the issue(s) by the Parties;
- Information gathering;
- Issue identification;
- Determination and discussion of options; and
- A written Mediation Settlement Agreement.

Once the mediation process begins, Parties may discuss their interests and concerns with the mediators (and particularly with the Lead Mediator, if any) at any time.

In some cases, the Parties and mediators may agree that the mediation will adjourn and reconvene at a later agreed upon time and place. All participants should give the mediation every chance to resolve the dispute. Because mediation is a voluntary process, at any time, any participant may comment on any aspect of the process or propose changes. Also at any time, either Party or the mediators have the authority to terminate the mediation for any reason. If the mediation terminates without a written Mediation Settlement Agreement, either Party is free to pursue all other available legal, regulatory, administrative or grievance procedures.

Introductory Remarks

Early in the mediation, at a time when all participants are present, the mediators will introduce themselves and ask the participants to do likewise. Some mediators may make comments about what they see as the nature of the dispute and seek to confirm or clarify some of the factual data from the introductory information.

The mediators or Lead Mediator may describe ground rules intended to help the mediation move smoothly. Ground rules may include such things as turning off beepers and cell phones, appropriate conduct, mutual respect, note taking, and any other special instructions concerning the mediation. The mediators shall remind the Parties that the mediation process is confidential, whether or not it results in settlement.

From time to time during the mediation, the mediators may ask each Party's participants to meet separately from the other Party, or to "caucus," in order to discuss aspects of the dispute and possible resolution among themselves or with some or all of the mediators. Throughout the process, Parties should try not to interrupt each other; the mediators will give each Party the opportunity to fully share their side.

Statements of the Issue (s) by the Parties

The mediators will allow each Party the opportunity to explain, without interruption, its position and perception of the dispute. This statement is not necessarily a recital of the facts, but it is to give each Party an opportunity to frame the issues and to give the mediator more information on the Party's position. If a Party's attorney(ies) make the initial statement, the mediators may also invite the Party's other participants to supplement the statement. The intent is for each Party and the mediators to better understand the other Party's position or point of view.

Information Gathering

The mediators may ask one or both Parties questions, repeat back key ideas to the Parties, and summarize their understandings. This helps the mediators and Parties build rapport and ensure common understanding. Mediators will attempt to identify common agreements on the facts and to steer the discussion increasingly towards the future rather than merely reiterating the past.

Issue Identification

The mediators will try to identify the Parties' goals and interests in order to reach agreement on the nature of the issues that must be addressed in any resolution and the relationships between those issues. For example, a particular resolution of one issue may necessarily require a certain approach to another issue, or one issue must be resolved prior to another issue being resolved or even meaningfully discussed. It is possible that at some point the Parties may conclude that one or more of their issues cannot be resolved through the mediation, but nonetheless decide to set those aside for later proceedings and move on to resolve through the mediation their other disputed issues.

Determination and Discussion of Options

Methods for developing options may include caucuses, group processes, discussion groups or sub-groups, developing hypothetical plausible scenarios, or a mediator's proposal where the mediator puts a proposal on the table and the Parties take turns modifying it. If a caucus is held, discussions in the caucus are confidential and the mediators will not share those discussions with the other Party unless the Party in the caucus specifically asks them to do so.

To better explore potential solutions, the mediators may propose one or more brainstorming sessions by the Parties together or separately in caucus. This can lead to a final agreement, which diffuses the conflict and provides a new basis for future relations. The goal is to find some common ground by exploring lots of options, and to create possible solutions for the Parties to consider. Especially when meeting separately in caucus, through this process a Party may be able to entertain alternative solutions without committing to them as concessions.

Written Mediation Settlement Agreement

Mediation may be terminated at any time by either Party or by the mediators, but mediation has only successfully resolved the subject dispute when the Parties have executed a written Mediation Settlement Agreement.

As the Parties reach a sense that they may be able to agree on all or some of the issues being mediated, the Parties and mediators can begin crafting language to address resolutions of the issues comprising the dispute. This language must be satisfactory to both Parties. The elements and wording of the

agreement must be those of the Parties, and need to be specific enough that the Parties' intentions will be clear to others who may read it and to each participant at a later time.

It is important that each element of the Mediation Settlement Agreement be listed separately and be specific, measurable, achievable, realistic, and set to a timetable.

The draft Mediation Settlement Agreement probably will be reviewed and revised repeatedly by each Party and will continue to be edited, expanded, condensed, and rewritten as necessary until both Parties reach an acceptable settlement. Only after final agreement is reached on all its parts, and a final version memorialized in writing, will the Parties be asked to sign the Mediation Settlement Agreement to indicate their understanding of and agreement to the Mediation Settlement Agreement and their willingness to abide by its provisions.

The Parties' mutual execution of the Mediation Settlement Agreement resolves the dispute (or at least those aspects of the dispute addressed in the Mediation Settlement Agreement if they decided to set aside any specific issues for later proceedings). An executed Mediation Settlement Agreement is enforceable between the Parties in accordance with federal and state law.

Chapter 3: Revision History

Date Version	Number	Comments
December 08, 2008	1.0	Approved by the Compliance and Certification Committee
May 06, 2009	1.0	Approved by the Board of Trustees
November 29, 2017	2.0	Approved by Compliance and Certification Committee
August 16, 2018	2.0	Approved by the Board of Trustees

CCCPP-006-2 Mediation Procedures – Redline

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



~~NERC Compliance and Certification Committee Mediation Procedures~~

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NERC Compliance and Certification Committee Mediation Procedures

CCC Monitoring Program – CCCPP-006-~~1~~2
Effective: ~~June 10, 2010~~[proposed date]
Version ~~1~~2.0

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NERC Compliance and Certification Committee		CCCPP-006-1
Title: Mediation Procedures		
Version: 1.0	Revision Date: n/a	Effective Date: June 10, 2010

Summary:

The NERC Compliance and Certification Committee (CCC) Mediation Program is designed as an informal, voluntary process in which a CCC mediation panel assists NERC and a Regional Entity to understand and work through disagreements or disputes concerning NERC performance audits of a Regional Entity's Compliance Monitoring and Enforcement Program.

Revision History

Date Version	Number	Comments
12/09/08	1.0	Approved by the Compliance and Certification Committee
05/06/09	1.0	Approved by the Board of Trustees

~~Table of Contents~~

Preface i

Introduction iv

Chapter 1: Mediators 1

Chapter 2: Mediation Process 2

Introductory Remarks 2

Statements of the Issue (s) by the Parties 3

Information Gathering 3

Issue Identification 3

Determination and Discussion of Options 3

Written Mediation Settlement Agreement 3

Chapter 3: Revision History 5

~~1. Introduction ..... 1~~

~~2. Mediators ..... 2~~

~~3. Mediation Process ..... 3~~

~~Introductory Remarks ..... 3~~

~~Statements of the Issue (s) by the Parties ..... 4~~

~~Information Gathering ..... 4~~

~~Issue Identification ..... 4~~

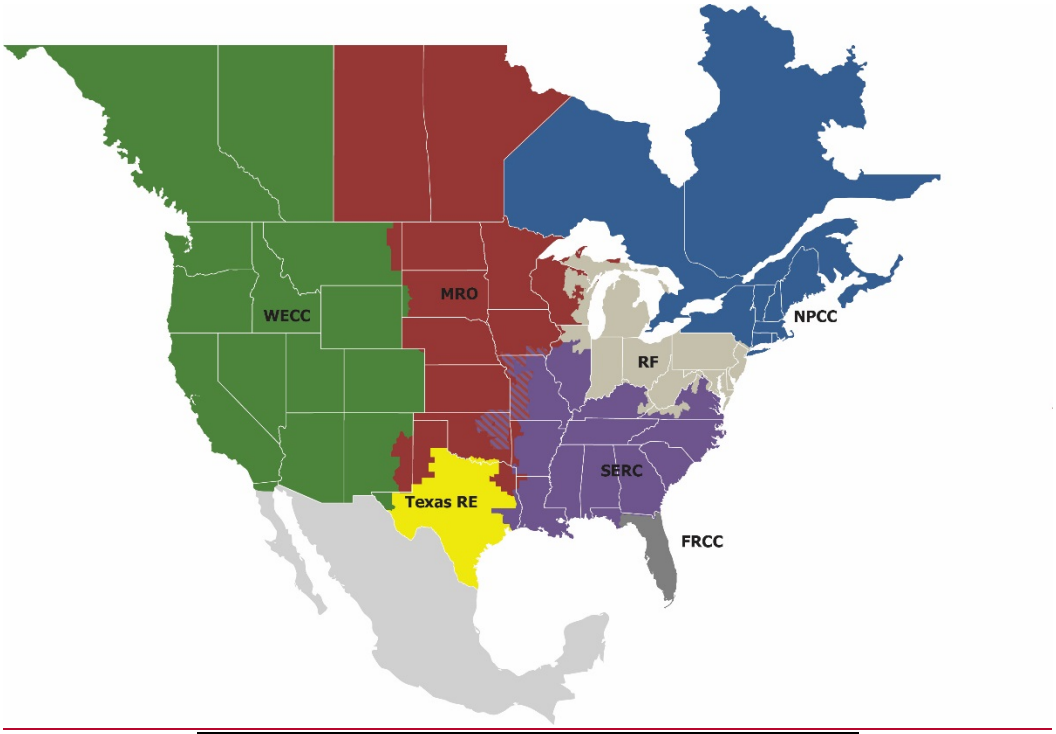
~~Determination and Discussion of Options ..... 4~~

~~Written Mediation Settlement Agreement ..... 4~~

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The North American BPS is divided into seven Regional Entity 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.

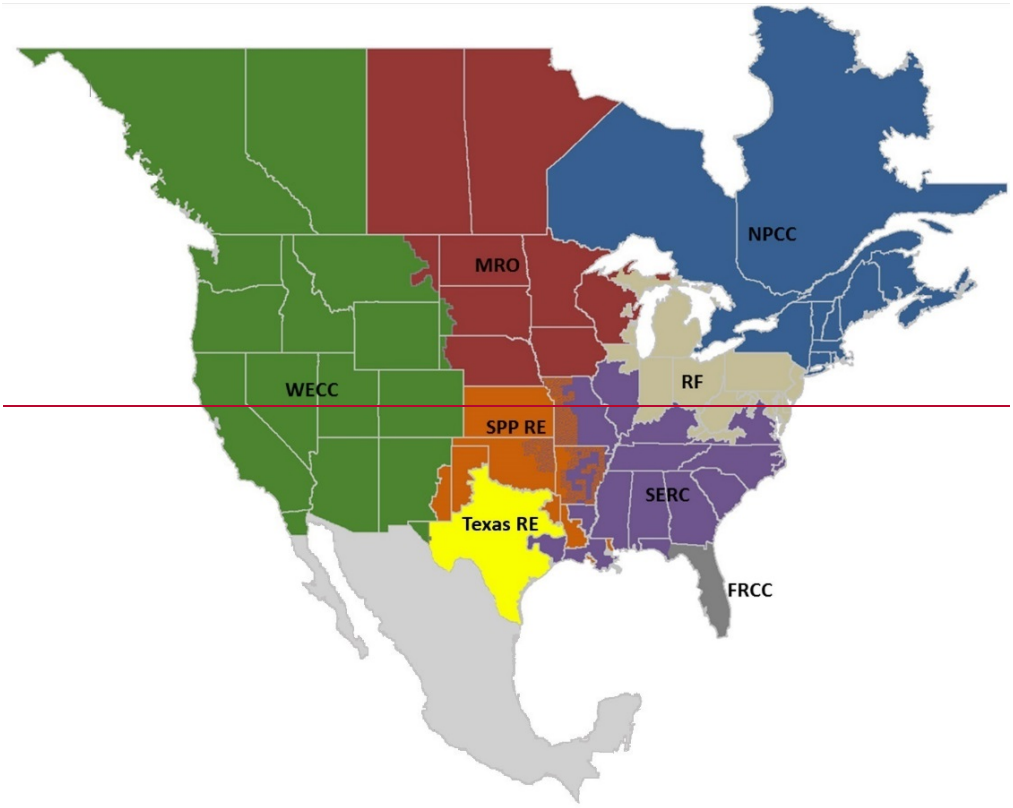


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The North American BPS is divided into eight RE boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight RE boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

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RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity

~~**Texas RE**~~	~~Texas Reliability Entity~~
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This alternative dispute resolution mechanism is intended to be a more collaborative, less adversarial method to attain a mutually agreeable resolution to the dispute, consistent with the NERC Rules of Procedure and without formal hearing proceedings.

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Written Mediation Settlement Agreement

Mediation may be terminated at any time by either Party or by the mediators, but mediation has only successfully resolved the subject dispute when the Parties have executed a written Mediation Settlement Agreement.

As the Parties reach a sense that they may be able to agree on all or some of the issues being mediated, the Parties and mediators can begin crafting language to address resolutions of the issues comprising the dispute. This language must be satisfactory to both Parties. The elements and wording of the agreement must be those of the Parties, and need to be specific enough that the Parties' intentions will be clear to others who may read it and to each participant at a later time.

It is important that each element of the Mediation Settlement Agreement be listed separately and be specific, measurable, achievable, realistic, and set to a timetable.

The draft Mediation Settlement Agreement probably will be reviewed and revised repeatedly by each Party and will continue to be edited, expanded, condensed, and rewritten as necessary until both Parties reach an acceptable settlement. Only after final agreement is reached on all its parts, and a final version memorialized in writing, will the Parties be asked to sign the Mediation Settlement Agreement to indicate their understanding of and agreement to the Mediation Settlement Agreement ~~and an~~and their willingness to abide by its provisions.

The Parties' mutual execution of the Mediation Settlement Agreement resolves the dispute (or at least those aspects of the dispute addressed in the Mediation Settlement Agreement if they decided to set aside any specific issues for later proceedings). An executed Mediation Settlement Agreement is enforceable between the Parties in accordance with federal and state law.

Chapter 3: Revision History

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December 08, 2008	1.0	Approved by the Compliance and Certification Committee
May 06, 2009	1.0	Approved by the Board of Trustees
November 29,2017	2.0	Approved by Compliance and Certification Committee
TBD	2.0	Approved by the Board of Trustees

Exhibit C

Comments on Proposed Revisions

From:	Kelsi.Rigby@aps.com
To:	ROPComments
Cc:	Nicholas.Kirby@aps.com
Subject:	Arizona Public Service Company"s Comments on Proposed Revisions to the NERC Rules of Procedure Appendix 4E
Date:	Friday, May 25, 2018 11:28:43 AM
Attachments:	image001.png

AZPS submits below its comments on the proposed revisions to rules of procedure appendix 4E. AZPS also submits minor errata and non-substantive observations for consideration.

Comments

With regard to the proposed changes to CCCPP-004, footnote 1 in § 1.5.7(b)(1) could be construed as permitting Staff to withhold exculpatory evidence under some conditions. AZPS recommends amending Footnote 1 of as follows:

> Staff shall not withhold any document, or the applicable part(s) thereof, that contains exculpatory evidence. Nothing in these subsections authorizes Staff to withhold a Document, or a part thereof, that contains exculpatory evidence. Nothing in these subsections requires Staff to withhold a Document from disclosure.

Errata

AZPS also submits for consideration the following errata and non-substantive observations:

CCCPP-004 – Hearing Procedures

- The section referencing is inconsistent throughout. For example, Section 1.4.3(b) proceeds to Section 1.4.3(a), and Section 1.4.4(a) proceeds to Section 1.4.4(a).
- Use of Respondent vs. Registered Entity is inconsistent throughout the document; capitalization of Respondent is inconsistent throughout the document
- 1.1.5 - The definition of "Hearing Panel" includes the term "Hearing Panel**"**
- 1.2.4(b) – "Any" does not need to be capitalized
- 1.2.4(c) – "and" could be struck; consider adding "or" between "prepaid, registered"
- 1.3.1(b)(2)(b) – "A" does not need to be capitalized
- 1.4.3(b) – This section could be struck as it is duplicative of the information provided in Sections 1.1.1 and 1.1.5. If this section is not struck, then "two industry sector" should be replaced with "two industry sectors"
- 1.5.2(b) – Should this section reference "Testimonial Hearing" instead of "Evidentiary Hearing" if testimony is contemplated? The definitions do not appear to support interchangeability, and a Testimonial Hearing encompasses an Evidentiary Hearing, but an Evidentiary Hearing does not contemplate testimony.
- 1.5.10 – Consider adding BCSI as a type of information to be considered entitled to protection through a protective order.
- 1.5.12 – This section could be simplified.

CCCPP-006 – Mediation

- Chapter 1: Mediations, paragraph 3, first sentence: Mediation is an informal process

and is only successful when a mutually agreeable resolution occurs;. ŧThere is no single correct procedure required for mediators to follow.

Thanks,



Kelsi Rigby
Regulatory Project Consultant, NERC
400 North 5th Street, Phoenix, AZ 85004-3902, M.S. 9712
Tel 602 250 2965
Kelsi.Rigby@aps.com | **aps.com**

May 28, 2018

ROPcomments@nerc.net

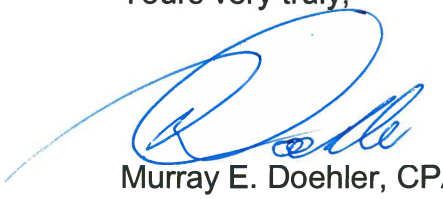
Compliance and Identification Committee:

We have reviewed the proposed changes to the "NERC Compliance and Certification Committee Hearing Procedure".

We do not have any comments about the proposed changes. Our issue is with what appears to be missing; i.e. a specific reference that NERC does not have the jurisdiction to apply these procedures in Canada. Any hearing, and the related procedures, are wholly under the jurisdiction of the utility's provincial regulator with responsibility for these matters.

An addition to the rules would be helpful in clarifying this issue.

Yours very truly,



Murray E. Doehler, CPA, CA, P.Eng.
CAMPUT MRC Representative

200 North Service Road West, Unit #1, Suite 646, Oakville, ON L6M 2Y1

Proposed Revisions to NERC Rules of Procedure, Appendix 4E (CCCPP-004 NERC Compliance and Certification Committee Hearing Procedures and CCCPP-006 Mediation Procedures)

Comments by Southwest Power Pool, Inc.

Southwest Power Pool, Inc. respectfully requests the drafting team consider the following comments and recommendations:

CCCPP-004 and CCCPP-006 documents:

1. Title Page – Will the effective dates be updated to reflect the implementation of Version 2.0 prior to submission to the Federal Energy Regulatory Commission? The current redline reflects effective dates of "June 10, 2010, Version 1.0" for CCCPP-004-2 and CCCPP-006-2.

2. Preface section – The map displaying the Regional Entity boundaries and corresponding information should be revised to delete references to the SPP RE, which will be dissolved on August 31, 2018.

3. Suggest a document scrub to ensure consistent fonts and point size are used throughout the documents (e.g., CCCPP-006 Table of Contents and chapters are different fonts, CCCPP-004 Section 1.3.1(d) appears to contain different font and point sizes).

CCCPP-004 document:

1. Suggest a document scrub to ensure the short forms for defined terms are used after the initial reference (e.g., in Section 1.1.1 (Procedure Governed) the term Regional Entity could be revised to be "RE" consistent with how it is identified in the Preface).

2. Suggest a document scrub to ensure consistency in section identification (e.g., Section 1.3.1 (Registered Entity's Option to Request a Hearing) appears to have two sections identified as "(a)" and two sections identified as "(b)."

3. Recommend rephrasing the intro to Section 1.1.5 (Definitions) to utilize language consistent with ROP Appendix 2 (*See* Appendix 2 at General) (recommended edits are highlighted in yellow below): "Unless otherwise defined~~, as used~~ in these Hearing Procedures, capitalized terms shall have the meanings set forth in Appendix 2 of the NERC Rules of Procedure ~~shall apply~~."

4. In section 1.1.5 (Definitions), two distinct terms appear to be combined into a single definition. Recommend revising this definition to separate the following two distinct definitions (recommended edits are highlighted in yellow below):
    a. Current:

"Board" or "Board of Trustees" means the Board of Trustees of NERC. "Board of Trustees Compliance Committee," "BOTCC" or "Compliance Committee" means the Compliance Committee of the NERC Board of Trustees.

b. Recommended:
   i. "Board" or "Board of Trustees" means the NERC Board of Trustees ~~of NERC~~."

   ii. "Board of Trustees Compliance Committee," "BOTCC," or "Compliance Committee" means the Compliance Committee of the ~~NERC~~ Board of Trustees.

CCCPP-006 document:

1. Suggest a document scrub to ensure the short forms for defined terms are used after the initial reference (e.g., Both the Preface and Introductory sections identify a short form of reference for the North American Electric Reliability Corporation (i.e., NERC) and a Regional Entity (i.e., RE)).

2. Chapter 1 (Mediators) – Third paragraph sentences require a conjunction to connect the two independent clauses (recommended edits are highlighted in yellow below):

   a. "Mediation is an informal process and is only successful when a mutually agreeable resolution occurs; however, there is no single correct procedure required for mediators to follow."

   b. "In any specific matter, one or more mediators may elect to discuss individual issues and concerns with one or more of the Parties prior to the session or one or more mediators may elect to wait until the mediation session to hold any discussion."

3. Chapter 2 (Mediation Process) – Consider revising the following sentences (recommended edits are highlighted in yellow below):

   a. "Also at any time, either Party or the mediators have the authority to terminate the mediation for any reason."

   b. "Only after final agreement is reached on all its parts, and a final version memorialized in writing, will the Parties be asked to sign the Mediation Settlement Agreement to indicate their understanding of, and agreement to, the Mediation Settlement Agreement and their willingness to abide by its provisions.

via e-mail to ROPcomments@nerc.net

COMMENTS OF TRANSMISSION ACCESS POLICY STUDY GROUP ON APRIL 13, 2018 POSTING OF PROPOSED REVISIONS TO RULES OF PROCEDURE APPENDIX 4E

TAPS appreciates the opportunity to comment on the proposed changes to Appendix 4E of the NERC Rules of Procedure, which the April 13, 2018 Notice states are intended "to align the rules and procedural steps to the Rules of Procedure governing an appeal of a Regional Entity decision." We have no substantive comments, but wish to draw your attention to the fact that the proposed changes seem not to take into account the proposed changes to the CMEP Hearing Procedures posted in January 2018. While those changes to the CMEP are not yet in effect, they were approved at the February 2018 Board of Trustees meeting, and it seems counterproductive to conform the CCC procedures to a soon-to-be-obsolete version of the CMEP procedures. We have not conducted a thorough review of the proposed changes, but note two examples.

First, Section 1.1.4 of the CCC procedures includes new subsection (b): "Any ruling, order, or decision of the Hearing Officer referenced in these Hearing Procedures shall be made by the Hearing Panel where the composition of the Hearing Panel consists of independent members and an independent Hearing Officer." The corresponding text has been deleted from Section 1.1.4 of the CMEP, and should accordingly be deleted from the CCC procedures.

Similarly, the Definitions section (1.1.5) has been deleted from the CMEP Hearing Procedures and should be deleted from the CCC procedures as well. At minimum, if the definitions are retained in the CCC procedures, they should be made consistent with the definitions in ROP Appendix 2; for example, in the definition of "Penalty," "Respondent" should be capitalized consistently.

TAPS appreciates the opportunity to submit these comments.

Exhibit D

Consideration of Comments

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Consideration of Comments

Proposed Changes to Appendix 4E of the NERC Rules of Procedure Related to the Compliance and Certification Committee's Hearing and Mediation Procedures

NERC thanks all commenters who submitted comments on the proposed changes to the Rules of Procedure (ROP). NERC held a 45-day public comment period for revisions to Appendix 4E from April 13, 2018, through May 28, 2018. NERC received four (4) sets of comments from industry stakeholders in response to the proposed revisions, as shown in the table on the following pages.

The comments are posted on the NERC Rules of Procedure page.

Table of Contents

I. List of Commenters..... ii

II. Comments..... 1

I. List of Commenters

Organization	
1.	Arizona Public Service Company ("AZPS")
2.	Camput MRC ("Camput")
3.	Southwest Power Pool, Inc. ("SPP")
4.	Transmission Access Policy Study Group ("TAPS")

II. Comments

Commenters were generally supportive of the proposed changes and offered the following comments and suggested modifications, as discussed below.

The North American Electric Reliability Corporation ("NERC") proposed revisions to Appendix 4E of its Rules of Procedure ("ROP"), which governs the Compliance and Certification Committee's ("CCC's") Hearing Procedures, to better align the Hearing Procedures found therein with the Hearing Process conducted by the Regional Entities ("REs"). The CCC is an independent stakeholder committee responsible for monitoring NERC's adherence to its ROP regarding Reliability Standards development and compliance as well as the execution of its compliance, enforcement, registration, and certification programs. The CCC's Hearing Procedures delineate its designated function as an appellate hearing body with the authority to review findings, penalties, and sanctions enforced by NERC in cases where NERC directly monitored compliance. The CCC's Mediation Procedures delineate its designated function as the mediator for any disagreements between NERC and the REs regarding performance audits of RE compliance programs.

The proposed revisions were made in accordance with the CCC Charter requirement that CCC Hearing Procedures follow the approved RE Hearing Process unless specifically identified otherwise. NERC's proposed revisions to CCCPP-004 are focused on aligning the terminology and structure of the CCC Hearing Procedures and the RE Consolidated Hearing Process through format and structural changes, as well as revisions and additions that provide clarification. For CCCPP-006, there were no substantive changes; instead NERC updated the procedure to match NERC's most current template to provide symmetry with CCCPP-004.

Topic Area	Summary of Stakeholder Comments	Action/Response and Notes
Withholding of Exculpatory Evidence	• AZPS recommends that CCCPP-004 Footnote 1 in § 1.5.7(b)(1) be amended to add "Staff shall not withhold any document, or the applicable part(s) thereof, that contains exculpatory evidence."	• AZPS' proposed addition goes substantively farther than NERC's ROP by forbidding Staff to withhold documents containing exculpatory evidence, whereas NERC's language merely indicates that this section does not give Staff the authority to do so. Other sources of law or authority may still require Staff to withhold exculpatory evidence, and the NERC ROP does not intend to overrule that. Because the proposed language unreasonably extends NERC's authority, NERC must decline to implement this proposed change.

Topic Area	Summary of Stakeholder Comments	Action/Response and Notes
Applicability of CCC Hearing Procedures in Canada	• Camput recommends adding a specific reference that "NERC does not have the jurisdiction to apply these procedures in Canada."	• The language of Section 1.1.1 specifically limits the CCC Hearing Procedures to hearings in the United States. Nevertheless, NERC added an additional reference providing that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions.
Consideration of Proposed Changes to the CMEP Hearing Procedures	• TAPS provided several examples and expressed a general concern that the proposed changes to Appendix 4E did not take into consideration all changes to the CMEP Hearing Procedures approved by FERC in June 2018.	• NERC has verified and, where appropriate, revised the proposed changes to Appendix 4E to ensure its alignment with the Rules of Procedure effective June 8, 2018.
Consistent Section Referencing	• AZPS suggests fixing the Section headings. AZPS cites 1.4.3(b) preceding 1.4.3(a) as one example. AZPS cites 1.4.4(a) preceding 1.4.4(a) as another example.	• NERC notes the apparent error in headings was due to a redline format shift. The headings appear correctly in the clean version.
Striking Duplicative Text	• AZPS suggests striking Section 1.4.3(b) as duplicative because the information provided therein is already provided in Sections 1.1.1 and 1.1.5.	• The Section 1.4.3(b) explanation of Hearing Panel is identical to the combined text of 1.1.1 and 1.1.5. Nevertheless, NERC and the CCC support its reiteration in Section 1.4.3(b) for ease of reference and clarity.
Testimonial Hearing vs. Evidentiary Hearing in Section 1.5.2(b)	• AZPS expresses concern that Section 1.5.2(b) should be referencing "Testimonial Hearings" instead of "Evidentiary Hearings" because the definitions are not interchangeable.	• NERC intended to use the broader and more inclusive defined term, "Evidentiary Hearing," but the resulting confusion has caused NERC to reconsider. Both definitions were removed from Section 1.1.5 and the rest of Appendix 4E. Current references to the undefined term "evidentiary hearing" provide the broadest and most inclusive understanding available.
Consistent Terminology Use	• AZPS notes that "Respondent" and "Registered Entity" were used inconsistently to refer to the	• NERC has verified and, where appropriate, revised the proposed changes to Appendix 4E so that "Respondent" and

Topic Area	Summary of Stakeholder Comments	Action/Response and Notes
	same party throughout the document.	"Registered Entity" are used more consistently. • NERC notes, however, that "Respondent" and "Registered Entity" may be used at separate times to denote separate functions of the entities in question, as per the definition of "Respondent" in Appendix 2.
Definitions	• AZPS notes that the definition of "Hearing Panel" uses the term "Hearing Panel. • SPP recommends rephrasing the introduction to Section 1.1.5 (Definitions) to use language consistent with ROP Appendix 2, providing the following recommended revision: "Unless otherwise defined in these Hearing Procedures, capitalized terms shall have the meanings set forth in Appendix 2 of the NERC ROP." • SPP recommends revising the two-in-one definition of the "Board of Trustees" and the "Board of Trustees Compliance Committee" to read as two distinct definitions.	• Corrected to say "hearing body." • NERC has verified and, where appropriate, revised Section 1.1.5, Definitions, so that only definitions that substantially differ from Appendix 2 remain. Section 1.1.5, Definitions, now states "Unless otherwise defined below, capitalized terms used in these Hearing Procedures shall have the meanings set forth in Appendix 2 of the NERC Rules of Procedure." • NERC has removed these definitions from this section, which instead references Appendix 2.
Protective Orders	• AZPS suggests that NERC consider adding BES Cyber System Information (BCSI) as a type of information which can be protected through a protective order.	• NERC declines to add this clarification at this time because the purpose for these revisions was to align this language with the CMEP Hearing Process, putting this comment outside of the scope of the proposed change.
Simplification	• AZPS suggests that Section 1.5.12 be simplified.	• NERC has revised these hearing procedures to more accurately mirror 1.5.12 of the CMEP Hearing Process. Therefore, NERC declines to further edit this section for simplicity, as the changes would reduce the alignment of the two hearing procedures.

Topic Area	Summary of Stakeholder Comments	Action/Response and Notes
Effective Dates	• SPP questions whether the effective dates will be updated to reflect Version 2.0 prior to FERC submission, noting that the redline shows effective dates of "June 10, 2010, Version 1.0."	• Effective dates will reflect Version 2.0 prior to submission to FERC.
Regional Entity Boundary Maps	• SPP suggests that the map displaying Regional Entity (RE) boundaries should be revised to delete references to the SPP RE because of its August 31, 2018 dissolution date.	• The map of Regional Entities has been revised as of July 1, 2018, when the dissolution of SPP RE was complete.
CCCPP-004 Non-Substantive Typographic and Clerical Suggestions	• AZPS suggests that NERC revise the changes to CCCPP-004 to include the following grammatical and structural corrections: o Use consistent capitalization of the word "Respondent" throughout the document. o Fix the improper capitalization of the word "Any" in Section 1.2.4(b). o Strike the unnecessary "and" from Section 1.2.4(c). o Consider adding "or" between "prepaid" and "registered" in Section 1.2.4(c). o Fix the improper capitalization of the word "A" in Section 1.3.1(b)(2)(b). o Change "two industry sector" to "two industry sectors" in Section 1.4.3(b). • SPP suggests that NERC revise the changes to CCCPP-004 to include the following structural corrections: o Ensure consistent fonts and point sizes, noting that Section 1.3.1(d) contains	• All of the non-substantive typographic or clerical revisions suggested here have been adopted.

Topic Area	Summary of Stakeholder Comments	Action/Response and Notes
	different font and point sizes. o Ensure consistency in section identification, noting that Section 1.3.1 has two (a)s and two (b)s.	
CCCPP-006 Non-Substantive Typographic and Clerical Suggestions	• AZPS suggests that the first sentence of the third paragraph in *Chapter 1: Mediators* be split into two sentences to read as: "Mediation is an informal process and is only successful when a mutually agreeable resolution occurs. There is no single correct procedure required for mediators to follow." • SPP suggest that the first sentence of the third paragraph in *Chapter 1: Mediators* requires a conjunction and recommends placing "; however" between "occurs" and "there." • SPP suggests that NERC revise the changes to CCCPP-004 to include the following grammatical and structural corrections: o The second sentence of the third paragraph in *Chapter 1: Mediators* requires a conjunction and recommends placing "or" between "session" and "one." o The second to last sentence of the last paragraph of *Chapter 2: Mediation Process*, before Introductory Remarks, should include the word "have" between "mediators" and "the authority." o The last sentence of the second to last paragraph of	• AZPS and SPP each suggested different revisions to *Chapter 1: Mediators*. While both provided possible options, NERC has incorporated SPP's suggestion of adding the word "however" because it was simpler. • All other non-substantive typographic or clerical revisions suggested here have been adopted as appropriate.

Topic Area	Summary of Stakeholder Comments	Action/Response and Notes
	Chapter 2: Mediation Process, by adding commas around "and agreement to", and by eliminating the word "an" and replacing it with "and." o Ensure consistent fonts and point sizes, noting that the Table of Contents font is different than that used for the chapters.	
Use of Short Form for the North American Electric Reliability Corporation (NERC) and the Regional Entities (REs)	• SPP suggested that NERC ensure that short forms of defined terms are used after the initial reference, noting that "RE" and "NERC" both have examples of long form used after their initial introduction.	• NERC has adopted the short form for the North American Electric Reliability Corporation (NERC) after initial use. • NERC would prefer to avoid using the acronym "RE" to identify Regional Entities in these Hearing Procedures, as the document refers primarily to Registered Entities and using an acronym that is similar to both terms may create confusion.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

November 29, 2018

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: Informational Filing, Frequency Response Annual Analysis
Docket No. RM13-11-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits its 2018 Frequency Response Annual Analysis report for the administration and support of Reliability Standard BAL-003-1.1 – Frequency Response and Frequency Bias Setting ("Report"). The Report updates statistical analyses and calculations in the 2012 Frequency Response Initiative Report included with NERC's petition for approval of Reliability Standard BAL-003-1 and subsequent reports in this docket.[1]

The attached Report uses data from operating years 2014-2017 (December 1, 2013 through November 30, 2017) to: (i) analyze frequency events and interconnection frequency characteristics for BAL-003; and (ii) determine adjustment factors for calculating Interconnection Frequency Response Obligations ("IFROs"). This information is provided for consistency of the IFRO calculation, although, as noted below, the Report recommends application of 2016 IFRO values for operating year 2019.[2]

In particular, the Report references inconsistencies in IFRO calculations under BAL-003-1.1 that were detailed in last year's report. Due to these inconsistencies, IFRO values for operating year 2019 remain as calculated in 2015 for operating year 2016.[3] Frequency Response Obligations ("FROs") for individual Balancing Authorities will be allocated using 2017 generation and load data, consistent with BAL-003-1.1. Dynamic IFRO validations were not performed in this Report, as those IFROs did not change from those prescribed last year.[4]

The Report recommends that the current Project 2017-01 Standard Drafting Team ("SDT") continue to address the issues with BAL-003-1.1 included in the consolidated Standards Authorization

---

1 *See generally*, filings in the above captioned docket (these materials commonly refer to the standard as BAL-003-1, although BAL-003-1.1 is the latest version and currently effective). The 2012 Frequency Response Initiative Report was attached as Exhibit F to the original petition submitted on March 20, 2015.

2 *Id.*

3 *See, e.g.*, Report, at p. iv.

4 *Id.*, at p. 18.

Request for the project.[5] As stated in the Report, "[s]everal recommendations from the 2016 and 2017 FRAA reports are currently being pursued through analysis by NERC staff and through the standards development process by multi-phase revisions to the BAL-003-1.1 Standard."[6] As further discussed in the Report, NERC will also continue tracking frequency response performance across interconnections.

NERC is not requesting any Commission action on the instant filing. NERC respectfully requests that the Commission accept this filing for informational purposes only.

Respectfully submitted,

/s/ Candice Castaneda
Candice Castaneda

Counsel for North American Electric Reliability Corporation

cc: Official service list in Docket No. RM13-11-000

[5] SAR posted at, https://www.nerc.com/pa/Stand/Pages/Project201701ModificationstoBAL00311.aspx.
[6] Report, at p. iv.

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 29th day of November 2018.

Candice Castaneda

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2018 Frequency Response Annual Analysis

November 2018

RELIABILITY | ACCOUNTABILITY






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Table of Contents

Preface iii

Executive Summary iv

Recommendations iv

Introduction v

Chapter 1 : Interconnection Frequency Characteristic Analysis 1

Frequency Variation Statistical Analysis 1

Variations in Probability Density Functions 3

ERCOT's Frequency Characteristic Changes 5

Chapter 2 : Determination of Interconnection Frequency Response Obligations 6

Tenets of IFRO 6

IFRO Formulae 6

Determination of Adjustment Factors 7

Adjustment for Differences between Value B and Point C (CB_R) 7

Determination of C-to-B Ratio (CB_R) 8

Point C Analysis: One-Second versus Sub-second Data (CC_{ADJ}) Eliminated 9

Adjustment for Primary Frequency Response Withdrawal (BC'_{ADJ}) 9

Low-Frequency Limit 10

Credit for Load Resources 11

Determination of Maximum Allowable Delta Frequencies 11

Calculated IFROs 15

Comparison to Previous IFRO Values 15

Chapter 3 : Dynamics Analysis of Recommended IFROs 18

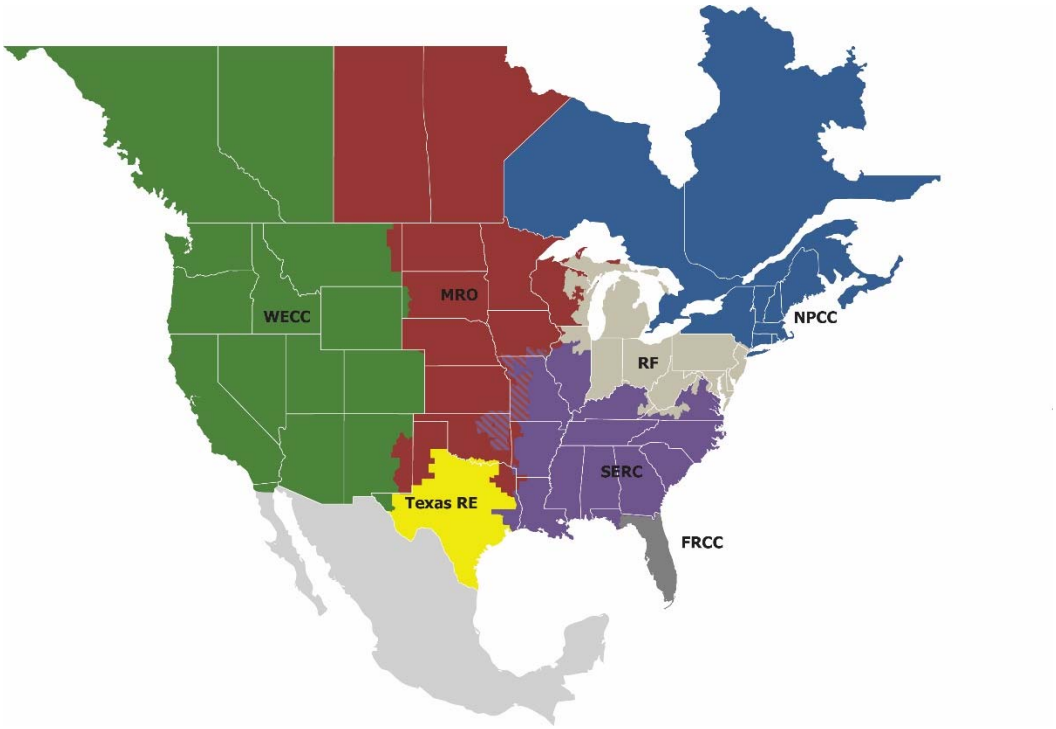
This report was approved by the Resources Subcommittee on November 2, 2018.

This report was endorsed by the Operating Committee on November 15, 2018.

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

Executive Summary

This report is the 2018 annual analysis of frequency response performance for the administration and support of NERC reliability *Standard BAL-003-1.1 – Frequency Response and Frequency Bias Setting.*[1] It provides an update to the statistical analyses and calculations contained in the *2012 Frequency Response Initiative Report*,[2] which was approved by the NERC Resources Subcommittee (RS) and Operating Committee (OC) and accepted by the NERC Board of Trustees (Board). This report, prepared by NERC staff,[3] contains the annual analysis, calculation, and recommendations for the interconnection frequency response obligation (IFRO) for each of the four electrical Interconnections of North America for the operating year 2019 (December 2018 through November 2019).

In accordance with the BAL-003-1 detailed implementation plan, and as a condition of approval by the RS and endorsement by the OC, these analyses are performed annually, and the results are published no later than November 20 each year.

Recommendations

The following recommendations are made for the administration of Standard BAL-003-1 for operating year 2019 (December 1, 2018 through November 30, 2019):

1. The IFRO values for operating year 2019 shall remain the same values as calculated in the *2015 Frequency Response Annual Analysis* (FRAA) report for operating year 2016[4] and held constant through operating years 2017 and 2018 as shown in **Table ES.1**.

Table ES.1: Recommended IFROs for Operating Year 2019

	Eastern (EI)	Western (WI)	ERCOT (TI)	Québec (QI)	Units
Recommended IFROs	**-1,015**	**-858**	**-381**	**-179**	**MW/0.1 Hz**
Absolute Value of Mean Interconnection Frequency Response Performance for Operating Year 2017[5]	2,257	1,836	835	748	MW/0.1 Hz

2. Frequency response withdrawal continues to be a characteristic of the Eastern Interconnection. The BC'_{ADJ} adjustment factor introduced in the *2012 Frequency Response Initiative Report* should continue to be tracked and used to adjust the IFRO as appropriate.

Outstanding Recommendations from the 2016 and 2017 FRAA Reports

Several recommendations from the *2016 and 2017 FRAA* reports[6] are currently being pursued through analysis by NERC staff and through the standards development process by multi-phase revisions to the BAL-003-1.1 Standard. Refer to those reports for additional details.

[1] http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.1.pdf
[2] http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf
[3] Prepared the NERC Standards and Engineering organization.
[4] These IFROs were held constant through operating years 2016, 2017, and 2018.
[5] Based on mean Interconnection frequency response performance from Appendix E of the *2018 State of Reliability* report for operating year 2017.
[6] http://www.nerc.com/comm/OC/Documents/2016_FRAA_Report_2016-09-30.pdf and https://www.nerc.com/comm/OC/BAL0031_Supporting_Documents_2017_DL/2017_FRAA_Final_20171113.pdf

Introduction

This report is the 2018 annual analysis of frequency response performance for the administration and support of NERC Reliability Standard BAL-003-1 – Frequency Response and Frequency Bias Setting.[7] It provides an update to the statistical analyses and calculations contained in the *2012 Frequency Response Initiative Report*[8] that were approved by the NERC RS, the OC, and accepted by the Board. No changes are proposed to the procedures recommended in the 2012 report at this time.

This report, prepared by NERC staff,[9] contains the annual analysis, calculation, and recommendations for the IFRO for each of the four electrical Interconnections of North America for the operating year 2019 (December 2018 through November 2019). This analysis includes the following:

- Statistical analysis of the interconnection frequency characteristics for the operating years 2014 through 2017 (December 1, 2013 through November 30, 2017)
- Analysis of frequency profiles for each Interconnection
- Calculation of adjustment factors from BAL-003-1 frequency response events
- A review of the dynamic analyses of each Interconnection performed in 2016 and 2017 for the recommended IFRO values.

This year's frequency response analysis builds upon the work and experience from performing such analyses since 2013. As such, there are several important things that should be noted about this report:

- The University of Tennessee–Knoxville (UTK) FNET[10] data used in the analysis has seen significant improvement in data quality, simplifying and improving annual analysis of frequency performance and ongoing tracking of frequency response events. In addition, NERC uses data quality checks to flag additional bad one-second data, including a bandwidth filter, least squares fit, and derivative checking. These data checking techniques resulted in no or minimal (+/- 0.001 Hz) change to starting frequency.
- As with the previous year's analysis, all frequency event analysis is using sub-second data from the FNET system frequency data recorders (FDRs). This eliminates the need for the CC_{ADJ} factor originally prescribed in the *2012 Frequency Response Initiative Report* because the actual frequency nadir was accurately captured.
- The frequency response analysis tool[11] is being used by the NERC Bulk Power System Awareness group for frequency event tracking in support of the NERC Frequency Working Group. The tool has expedited and streamlined Interconnection frequency response analysis. The tool provides an effective means of compiling frequency response events and generating a database of necessary values for adjustment factor calculations.

[7] http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.1.pdf
[8] http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf
[9] Prepared jointly by the System Analysis and Performance Analysis departments.
[10] Operated by the Power Information Technology Laboratory at the University of Tennessee, FNET is a low-cost, quickly deployable GPS-synchronized wide-area frequency measurement network. High-dynamic accuracy FDRs are used to measure the frequency, phase angle, and voltage of the power system at ordinary 120 V outlets. The measurement data are continuously transmitted via the Internet to the FNET servers hosted at the University of Tennessee and Virginia Tech.
[11] Developed by Pacific Northwest National Laboratory (PNNL).

Chapter 1: Interconnection Frequency Characteristic Analysis

Annually, NERC staff performs a statistical analysis[12] of the frequency characteristics for each of the four Interconnections. That analysis is performed to monitor the changing frequency characteristics of the Interconnections and to statistically determine the starting frequencies for the IFRO calculations. For this report's analysis, one-second frequency data[13] from operating years 2014–2017 (December 1, 2013 through November 30, 2017) was used.

Frequency Variation Statistical Analysis

The 2018 frequency variation analysis was performed on one-second frequency data for operating years 2014–2017 and is summarized in **Table 1.1**. This analysis is used to determine the starting frequency to be used in the IFRO calculations for each Interconnection.

This variability accounts for items such as time-error correction (TEC), variability of load, interchange, and frequency over the course of a normal day. It also accounts for all frequency excursion events.

Table 1.1: Interconnection Frequency Variation Analysis

Value	Eastern	Western	ERCOT	Québec
Time Frame (Operating Years)	2014–2017	2014–2017	2014–2017	2014–2017
Number of Samples	125,230,343	126,020,370	124,767,853	122,225,057
Filtered Samples (% of total)	99.7%	99.68%	98.8%	96.8%
Expected Value (Hz)	59.999	59.999	59.999	59.999
Variance of Frequency (σ^2)	0.00023	0.00036	0.00031	0.00041
Standard Deviation (σ)	0.01532	0.01890	0.01758	0.02019
50% percentile (median)	59.998	59.998	60.002	59.998
Starting Frequency (F_{START}) (Hz)	**59.974**	**59.966**	**59.968**	**59.967**

The starting frequency for the calculation of IFROs is the fifth-percentile lower-tail of samples from the statistical analysis, representing a 95 percent chance that frequencies will be at or above that value at the start of any frequency event. Since the starting frequencies encompass all variations in frequency, including changes to the target frequency during TEC, the need to expressly evaluate TEC as a variable in the IFRO calculation is eliminated.

Figures 1.1 through **Figures 1.4** show the probability density function of frequency for each Interconnection. The vertical red line is the fifth percentile frequency; the interconnection frequency will statistically be greater than that value 95 percent of the time. This value is used as the starting frequency.

[12] Refer to the 2012 *Frequency Response Initiative Report* for details on the statistical analyses used.

[13] One-second frequency data for the frequency variation analysis is provided by the University of Tennessee Knoxville (UTK). The data is sourced from FDRs in each Interconnection. The median value among the higher-resolution FDRs is down-sampled to one sample per second, and filters are applied to ensure data quality.

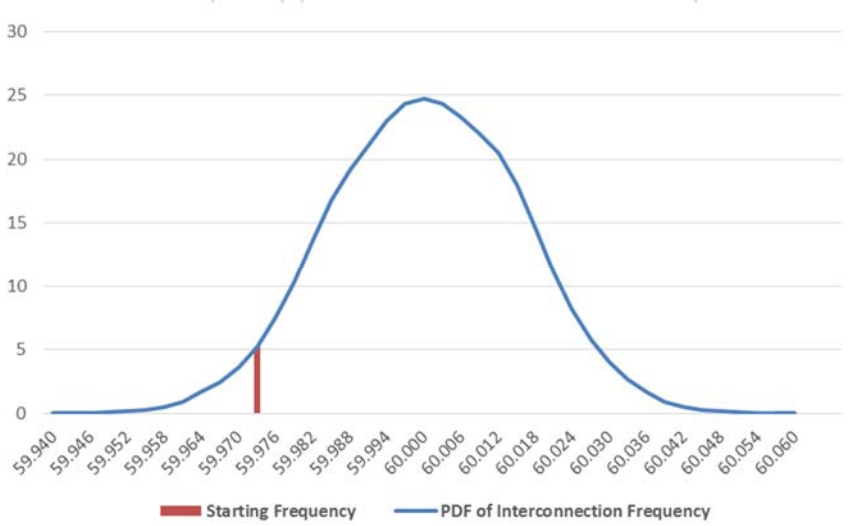


Figure 1.1: Eastern Interconnection 2014–2017 Probability Density Function of Frequency

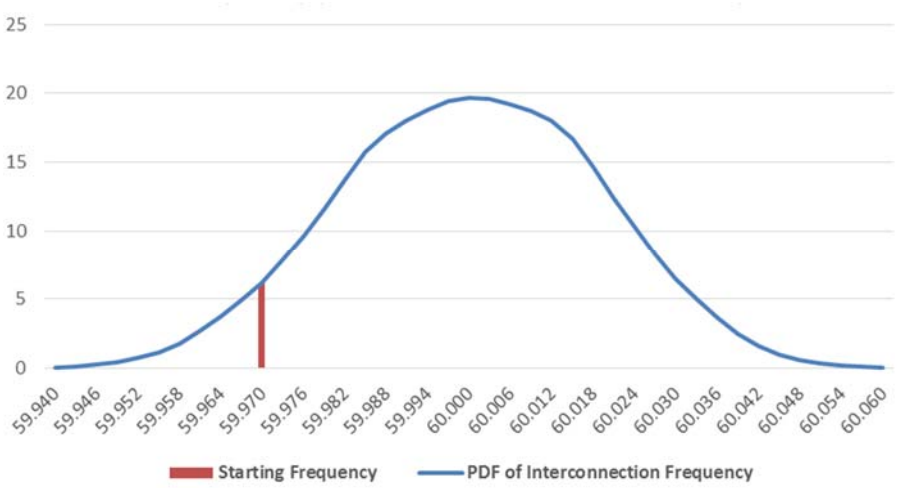


Figure 1.2: Western Interconnection 2014–2017 Probability Density Function of Frequency

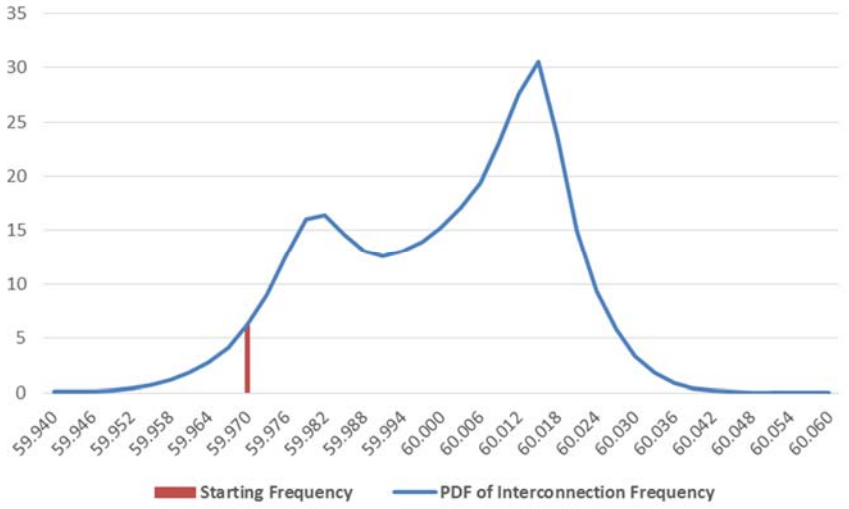


Figure 1.3: ERCOT Interconnection 2014–2017 Probability Density Function of Frequency

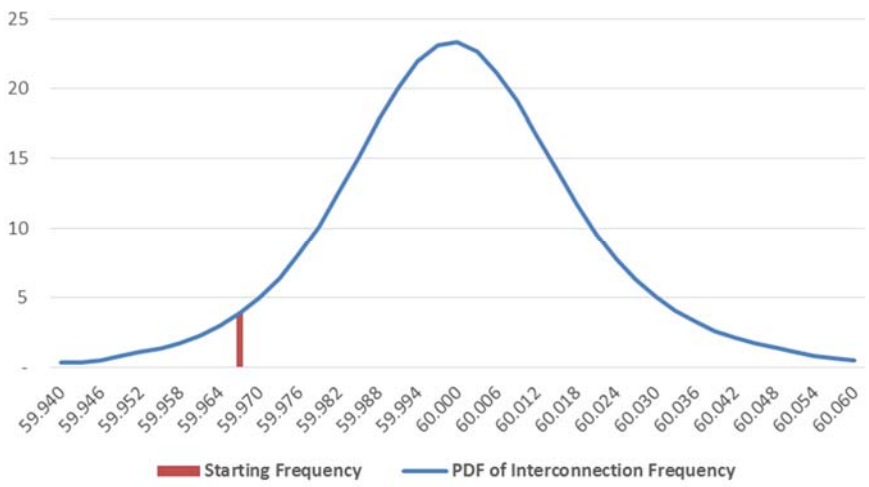


Figure 1.4: Québec Interconnection 2014–2017 Probability Density Function of Frequency

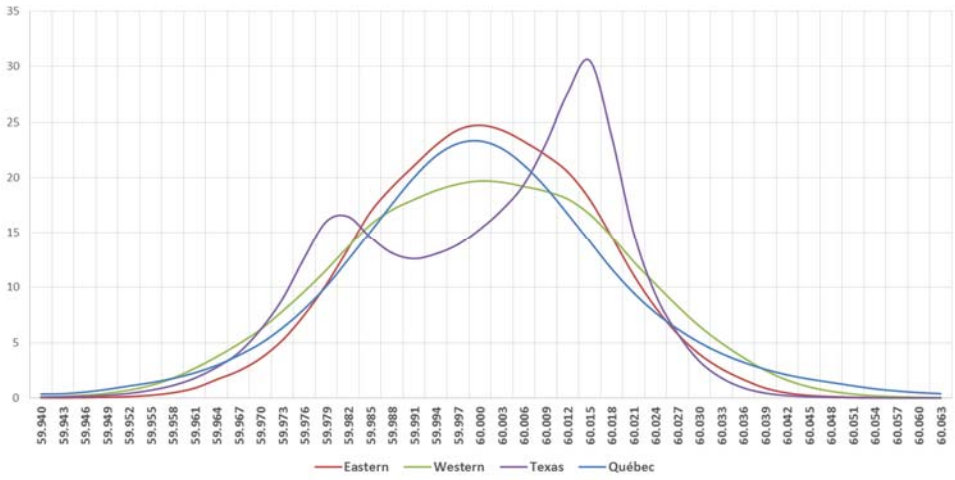


Figure 1.5: Comparison of 2014–2017 Interconnection Frequency Probability Density Functions

Variations in Probability Density Functions

The following is an analysis of the variations in probability density functions of the annual distributions of Interconnection frequency for years 2014 to 2017. **Table 1.2** lists the standard deviation of the annual Interconnection frequencies.

Table 1.2: Interconnection Standard Deviation by Year

Interconnection	2014	2015	2016	2017
Eastern	0.016	0.014	0.016	0.016
Western	0.019	0.019	0.019	0.019
ERCOT	0.020	0.017	0.016	0.016
Québec	0.020	0.020	0.020	0.020

For the Eastern Interconnection, the standard deviation in 2016 and 2017 increased compared to 2015 while in other interconnections standard deviations have been flat (Western and Québec) or decreasing (ERCOT). As a standard deviation is a measure of dispersity of values around the mean value, the decreasing standard deviation indicates tighter concentration around the mean value and more stable performance of the interconnection frequency in ERCOT. Changes in annual frequency profiles are further illustrated in **Figures 1.6 through 1.9**.

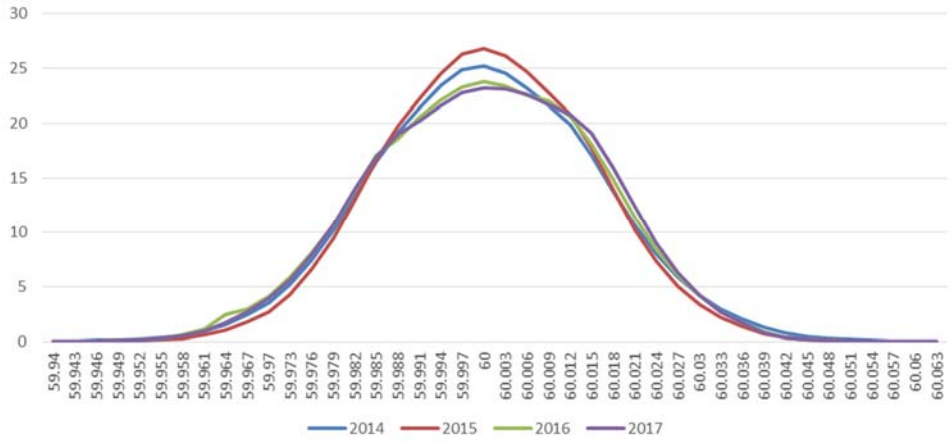


Figure 1.6: Eastern Interconnection Frequency Probability Density Function by Year

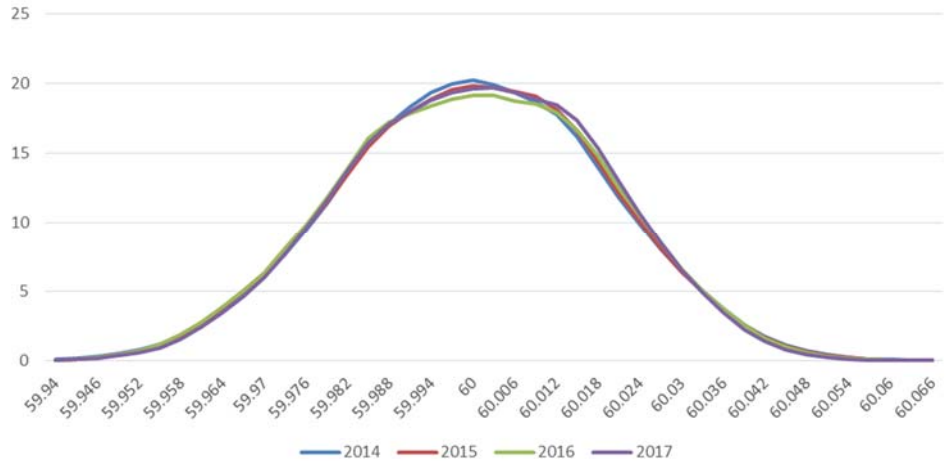


Figure 1.7: Western Interconnection Frequency Probability Density Function by Year

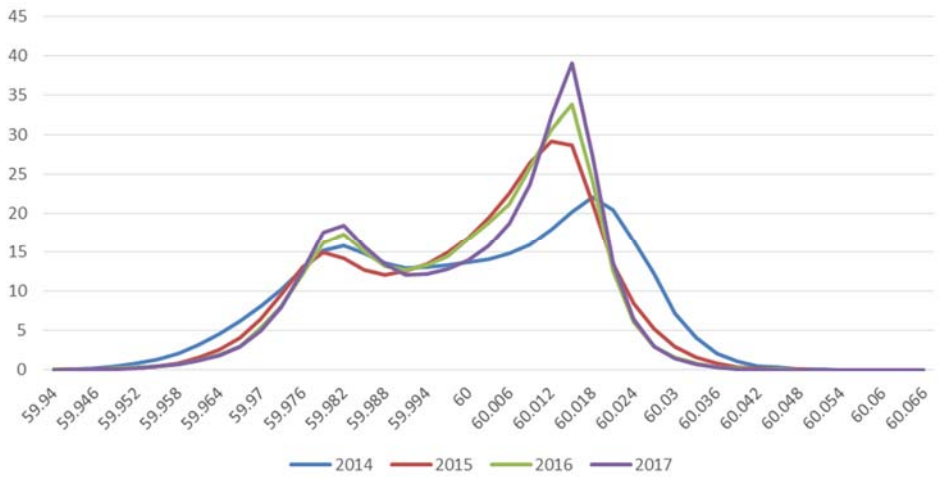


Figure 1.8: ERCOT Interconnection Frequency Probability Density Function by Year

ERCOT's Frequency Characteristic Changes

Standard TRE BAL-001[14] went into full effect in April 2015 and caused a dramatic change in the probability density function of frequency for ERCOT in 2015 and 2016. That standard requires all resources in ERCOT to provide proportional, non-step primary frequency response with a ±16.7 mHz dead-band. As a result, anytime frequency exceeds 60.017 Hz, resources automatically curtail themselves. That has resulted in far less operation in frequencies above the dead-band since all resources, including wind, are backing down. It is exhibited in **Figure 1.8** above as a probability concentration around 60.017 Hz. Similar behavior is not exhibited at the low dead-band of 59.983 Hz because most wind resources are operated at maximum output and cannot increase output when frequency falls below the dead-band.

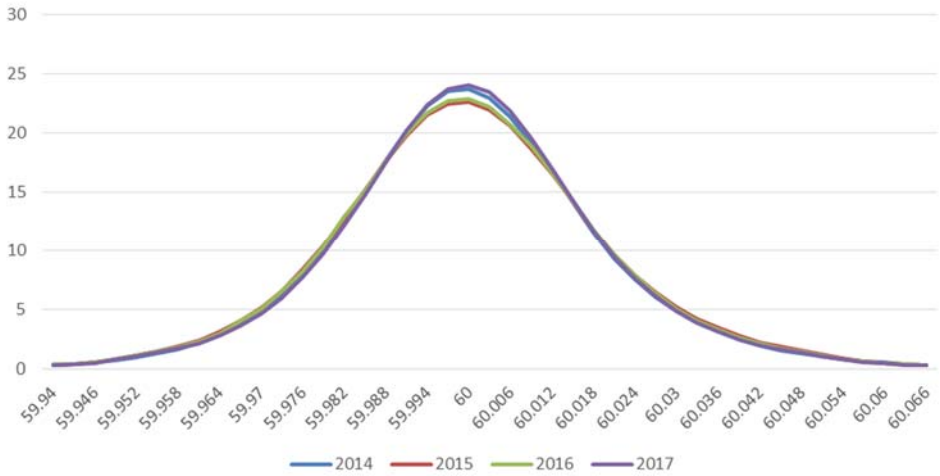


Figure 1.9: Québec Interconnection Frequency Probability Density Function by Year

[14] http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-TRE-1.pdf

Chapter 2: Determination of Interconnection Frequency Response Obligations

The calculation of the IFROs is a multifaceted process that employs statistical analysis of past performance; analysis of the relationships between measurements of Value A, Point C, and Value B; and other adjustments to the allowable frequency deviations and resource losses used to determine the recommended IFROs. Refer to the *2012 Frequency Response Initiative Report* for additional details on the development of the IFRO and the adjustment calculation methods.[15] The chapter is organized to follow the flow of the IFRO calculation as it is performed for all four interconnections.

Tenets of IFRO

The IFRO is the minimum amount of frequency response that must be maintained by an Interconnection. Each BA in the Interconnection should be allocated a portion of the IFRO that represents its minimum annual median performance responsibility. To be sustainable, BAs that may be susceptible to islanding may need to carry additional frequency-responsive reserves to coordinate with their UFLS plans for islanded operation.

A number of methods to assign the frequency response targets for each Interconnection can be considered. Initially, the following tenets should be applied:

- A frequency event should not activate the first stage of regionally approved UFLS systems within the interconnection.
- Local activation of first-stage UFLS systems for severe frequency excursions, particularly those associated with delayed fault-clearing or in systems on the edge of an Interconnection, may be unavoidable.
- Other frequency-sensitive loads or electronically coupled resources may trip during such frequency events as is the case for photovoltaic (PV) inverters.
- It may be necessary in the future to consider other susceptible frequency sensitivities (e.g., electronically coupled load common-mode sensitivities).

UFLS is intended to be a safety net to prevent system collapse from severe contingencies. Conceptually, that safety net should not be utilized for frequency events that are expected to happen on a relatively regular basis. As such, the resource loss protection criteria were selected as detailed in the *2012 Frequency Response Initiative Report* to avoid violating regionally approved UFLS settings.

IFRO Formulae

The following are the formulae that comprise the calculation of the IFROs:

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

$$DF_{CBR} = \frac{DF_{Base}}{CB_R}$$

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

$$ARLPC = RLPC - CLR$$

$$IFRO = \frac{ARLPC}{MDF}$$

[15] http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

Where:

- DF_{Base} is the base delta frequency.
- F_{Start} is the starting frequency determined by the statistical analysis.
- UFLS is the highest UFLS trip set point for the interconnection.
- CB_R is the statistically determined ratio of the Point C to Value B.
- DF_{CBR} is the delta frequency adjusted for the ratio of Point C to Value B.
- BC'_{ADJ} is the statistically determined adjustment for the event nadir occurring below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.
- MDF is the maximum allowable delta frequency.
- Resource loss protection criteria (RLPC) is the resource loss protection criteria.
- CLR is the credit for load resources.
- An RLPC is the adjusted resource loss protection criteria adjusted for the credit for load resources.
- IFRO is the interconnection frequency response obligation expressed in MW/0.1 Hz.

Note: The CC_{ADJ} adjustment has been eliminated because of the use of sub-second data for this year's analysis of the Interconnection frequency events. The CC_{ADJ} adjustment had been used to correct for the differences between one-second and sub-second Point C observations for frequency events. This also eliminates the DF_{CC} term from the original 2012 formulae.

Determination of Adjustment Factors

Adjustment for Differences between Value B and Point C (CB_R)

All of the calculations of the IFRO are based on avoiding instantaneous or time-delayed tripping of the highest set point (step) of UFLS, either for the initial nadir (Point C) or for any lower frequency that might occur during the frequency event. However, as a practical matter, the ability to measure the tie line and loads for a BA is limited to SCADA scan rates of one to six seconds. Therefore, the ability to measure frequency response at the BA level is limited by the SCADA scan rates available to calculate Value B. To account for the issue of measuring frequency response as compared with the risk of UFLS tripping, an adjustment factor (CB_R) is calculated from the significant frequency disturbances selected for BAL-003-1 operating years 2014 through 2017 (between December 1, 2013 to November 30, 2017), which captures the relationship between Value B and Point C.

Sub-Second Frequency Data Source
Frequency data used for calculating all of the adjustment factors used in the IFRO calculation comes from the "FNet /GridEye system" hosted by UTK and the Oak Ridge National Laboratory. Six minutes of data is used for each frequency disturbance analyzed, one minute prior to the event and five minutes following the start of the event. All event data is provided at a higher resolution (10 samples-per-second) as a median frequency from all the available frequency data recorders (FDRs) for that event.

Analysis Method

The IFRO is the minimum performance level that the BAs in an Interconnection must meet through their collective frequency response to a change in frequency. This response is also related to the function of the frequency bias setting in the area control error (ACE) equation of the BAs for the longer term. The ACE equation looks at the difference between scheduled frequency and actual frequency and times the frequency bias setting to estimate the amount of megawatts that are being provided by load and

generation within the BA. If the actual frequency is equal to the scheduled frequency, the Frequency Bias component of ACE must be zero.

When evaluating some physical systems, the nature of the system and the data resulting from measurements derived from that system do not always fit the standard linear regression methods that allow for both a slope and an intercept for the regression line. In those cases, it is better to use a linear regression technique that represents the system correctly. Since the IFRO is ultimately a projection of how the Interconnection is expected to respond to changes in frequency related to a change in megawatts (resource loss or load loss), there should be no expectation of frequency response without an attendant change in megawatts. It is this relationship that indicates the appropriateness of using regression with a forced-fit through zero.

Determination of C-to-B Ratio (CB_R)

The evaluation of data to determine the C-to-B ratio (CB_R) to account for the differences between arrested frequency response (to the nadir, Point C) and settled frequency response (Value B) is also based on a physical representation of the electrical system. Evaluation of this system requires investigation of the meaning of an intercept. The CB_R is defined as the difference between the pre-disturbance frequency and the frequency at the maximum deviation in post-disturbance frequency divided by the difference between the predisturbance frequency and the settled post-disturbance frequency.

$$CB_R = \frac{Value\ A - Point\ C}{Value\ A - Value\ B}$$

A stable physical system requires the ratio to be positive; a negative ratio indicates frequency instability or recovery of frequency greater than the initial deviation. The CB_R adjusted for confidence (**Table 2.1**) should be used to compensate for the differences between Point C and Value B. For this analysis, BAL-003-1 frequency events from operating years 2014 through 2017 (December 1, 2013 through November 30, 2017) were used.

Table 2.1: Analysis of Value B and Point C (CB_R)

Interconnection	Number of Events Analyzed	Mean	Standard Deviation	95% Confidence	CB_R Adjusted for Confidence
Eastern	112	1.107	0.169	0.027	1.134
Western	86	1.755	0.692	0.124	1.879
ERCOT	143	1.700	0.536	0.074	1.774
Québec	135	4.353	1.383	0.197	1.550

The Eastern Interconnection historically exhibited a frequency response characteristic that often had Value B below Point C, and the CB_R value for the Eastern Interconnection has been below 1.000. In those instances, the CB_R had to be limited to 1.000. However, the calculated CB_R in this year's analysis[16] indicates a value above 1.000, and no such limitation is required. This is due in large part to the improvement made to primary frequency response of the Interconnection through the outreach efforts by the NERC RS and the North American Generator Forum.

The Québec Interconnection's resources are predominantly hydraulic and are operated to optimize efficiency, typically at about 85 percent of rated output. Consequently, most generators have about 15 percent headroom to supply primary frequency response. This results in a robust response to most frequency events, exhibited by

[16] The same was true for the 2016 analysis.

high rebound rates between Point C and the calculated Value B. For the 135 frequency events in their event sample, Québec's CB_R value would be two to four times the CB_R values of other Interconnections. Using the same calculation method for CB_R would effectively penalize Québec for their rapid rebound performance and make their IFRO artificially high. Therefore, the method for calculating the Québec CB_R was modified, which limits the CB_R.

Québec has an operating mandate for frequency responsive reserves to prevent tripping their 58.5 Hz (300 millisecond trip time) first-step UFLS for their largest hazard at all times, effectively protecting against tripping for Point C frequency excursions. Québec also protects against tripping a UFLS step set at 59.0 Hz that has a 20-second time delay, which protects them from any sustained low-frequency Value B and primary-frequency response withdrawals. This results in a Point C to Value B ratio of 1.5. To account for the confidence interval, 0.05 is then added, making the Québec CB_R equal 1.550.

Point C Analysis: One-Second versus Sub-second Data (CC_{ADJ}) Eliminated

Calculation of all of the IFRO adjustment factors for this *2018 FRAA* utilized sub-second measurements from FNET FDRs. Data at this resolution accurately reflects the Point C nadir; therefore, a CC_{ADJ} factor is no longer required and has been eliminated.

Adjustment for Primary Frequency Response Withdrawal (BC'_{ADJ})

At times, the actual frequency event nadir occurs after Point C, defined in BAL-003-1 as occurring in the T+0 to T+12 second period, during the Value B averaging period (T+20 through T+52 seconds), or later. This lower nadir is symptomatic of primary frequency response withdrawal, or squelching, by unit-level or plant-level outer-loop control systems. Withdrawal is most prevalent in the Eastern Interconnection.

In order to track frequency response withdrawal in this report, the later-occurring nadir is termed Point C', and is defined as occurring after the Value B averaging period and must be lower than either Point C or Value B.

Primary frequency response withdrawal is important depending on the type and characteristics of the generators in the resource dispatch, especially during light-load periods. Therefore, an additional adjustment to the maximum allowable delta frequency for calculating the IFROs was statistically developed. This adjustment is used whenever withdrawal is a prevalent feature of frequency events.

The statistical analysis is performed on the events with C' value lower than Value B to determine the adjustment factor BC'_{ADJ} to account for the statistically expected Point C' value of a frequency event. Those results correct for the influence of frequency response withdrawal on setting the IFRO. **Table 2.2** shows a summary of the events for each Interconnection where the C' value was lower than Value B (averaged from T+20 through T+52 seconds) and those where C' was below Point C for operating years 2014 through 2017 (December 1, 2013 through November 30, 2017).

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

Only the Eastern Interconnection had a significant number of resource-loss events where C' was below Point C or Value B for those events. The 12 events detected for Québec are for load-loss events, indicated by the negative values for the Mean Difference and the BC'_{ADJ}; the adjustment is not intended to be used for load-loss events.

Although an event with C' lower than Point C was identified in the ERCOT Interconnection, it does not warrant an adjustment factor; only the adjustment factor of 6 mHz for the Eastern Interconnection is necessary. There were 66 out of 112 frequency events in that Interconnection exhibiting a secondary nadir (Point C') below value B and 34 out of those had Point C' lower than the initial frequency nadir (Point C). These secondary nadirs occur 72 to 90 seconds after the start of the event,[17] which is well beyond the time frame for calculating Value B.

Therefore, a BC'_{ADJ} is only needed for the Eastern Interconnection; no BC'_{ADJ} is needed for the other three Interconnections. This will continue to be monitored moving forward to track these trends in C' performance.

Recommendation:

NERC should continue to track and adjust for the withdrawal characteristics of the Eastern Interconnection.

Low-Frequency Limit

The low-frequency limits to be used for the IFRO calculations (**Table 2.3**) should be the highest step in the Interconnection for regionally approved UFLS systems. These values have remained unchanged since the *2012 Frequency Response Initiative Report*.

Table 2.3: Low-Frequency Limits (Hz)

Interconnection	Highest UFLS Trip Frequency
Eastern	59.5
Western	59.5
ERCOT	59.3
Québec	58.5

The highest UFLS set point in the Eastern Interconnection is 59.7 Hz in FRCC, while the highest set point in the rest of the Interconnection is 59.5 Hz. The FRCC 59.7 Hz first UFLS step is based on internal stability concerns and is meant to prevent the separation of the Florida peninsula from the rest of the Interconnection. FRCC concluded that the IFRO starting point of 59.5 Hz for the Eastern Interconnection is acceptable in that it imposes no greater risk of UFLS operation for an Interconnection resource loss event than for an internal FRCC event.

Protection against tripping the highest step of UFLS does not ensure generation that has frequency-sensitive boiler or turbine control systems will not trip, especially in electrical proximity to faults or the loss of resources. Severe system conditions might drive the combination of frequency and voltage to levels that present some generator and turbine control systems to trip the generator. Similarly, severe rates-of-change occurring in voltage or frequency might actuate volts-per-hertz relays, which would also trip some generators, and some combustion turbines may not be able to sustain operation at frequencies below 59.5 Hz.

Inverter-based resources may also be susceptible to extremes in frequency. Laboratory testing by Southern California Edison of inverters used on residential and commercial scale photovoltaic (PV) systems revealed a propensity to trip at about 59.4 Hz, which is 200 mHz above the expected 59.2 Hz prescribed in IEEE Standard

[17] The timing of the C' occurrence is consistent with outer-loop plant and unit controls causing withdrawal of inverter-based resource frequency response.

1547 for distribution-connected PV systems rated at or below 30 kW (57.0 Hz for larger installations). This could become problematic in the future in areas with a high penetration of inverter-based resources.

Credit for Load Resources

The ERCOT Interconnection depends on contractually interruptible (an ancillary service) demand response that automatically trips at 59.7 Hz by underfrequency relays to help arrest frequency declines. A credit for load resources (CLR) is made for the resource contingency for the ERCOT Interconnection.

The amount of CLR available at any given time varies by different factors, including its usage in the immediate past. NERC performed statistical analysis on hourly available CLR over a two-year period from January 2015 through December 2016, similar to the approach used in the 2015 and 2016 FRAA. Statistical analysis indicated that 1,209 MW of CLR is available 95 percent of the time. Therefore, a CLR adjustment of 1,209 MW is applied in the calculation of the ERCOT Interconnection IFRO as a reduction to the RLPC.

The 2016–2017 CLR for the ERCOT Interconnection was only 16 MW higher than the 1,193 MW adjustment in the 2016 IFRO calculation and 20 MW above the 1,181 MW adjustment in the 2015 IFRO calculation, showing consistency in the procurement and availability load resources to arrest frequency response in ERCOT.

CLR credit in future IFRO calculations for ERCOT is being reviewed by the BAL-003 Standard Drafting Team.

ERCOT Credit for Load Resources

Prior to April 2012, ERCOT was procuring 2,300 MW of responsive reserve service (RRS) of which up to 50 percent could be provided by the load resources with under-frequency relays set at 59.70 Hz. Beginning April 2012 due to a change in market rules, the RRS requirement was increased from 2,300 MW to 2,800 MW for each hour, meaning load resources could potentially provide up to 1,400 MW of automatic primary frequency response. This differs from the CLR in the Western Interconnection for the loss of two Palo Verde units, where the load is automatically tripped by a remedial action scheme.

Determination of Maximum Allowable Delta Frequencies

Because of the measurement limitation[18] of the BA-level frequency response performance using Value B, IFROs must be calculated in "Value B space." Protection from tripping UFLS for the Interconnections based on Point C, Value B, or any nadir occurring after Point C, within Value B, or after T+52 seconds must be reflected in the maximum allowable delta frequency for IFRO calculations expressed in terms comparable to Value B.

Table 2.4 shows the calculation of the maximum allowable delta frequencies for each of the Interconnections. All adjustments to the maximum allowable change in frequency are made to include the following:

- Adjustments for the differences between Point C and Value B
- Adjustments for the event nadir being below Value B or Point C due to primary frequency response withdrawal measured by Point C'

Only the Eastern Interconnection exhibits a meaningful amounts of frequency response withdrawal. Frequency response withdrawal will continue to be monitored.

[18] Due to the use of 1 to 6 second scan-rate data in BA's EMS systems to calculate the BA's Frequency Response Measures for frequency events under BAL-003-1

Table 2.4: Determination of Maximum Allowable Delta Frequencies					
	Eastern	**Western**	**ERCOT**	**Québec**	**Units**
Starting Frequency	59.974	59.966	59.968	59.967	Hz
Minimum Frequency Limit	59.500	59.500	59.300	58.500	Hz
Base Delta Frequency	0.474	0.466	0.668	1.467	Hz
CB_R[19]	1.134	1.879	1.774	1.550	Ratio
Delta Frequency (DF_{CBR})[20]	0.418	0.248	0.377	0.946	Hz
BC'_{ADJ}[21]	0.006	N/A	N/A	N/A	Hz
Max. Allowable Delta Frequency	0.412	0.248	0.377	0.946	Hz

Note: The adjustment for the differences one-second versus sub-second frequency data (CC_{ADJ}) is no longer required and has been eliminated. All Point C calculations for this *2018 FRAA* utilized sub-second measurements from FNET FDRs.

Comparison of Maximum Allowable Delta Frequencies

Several factors account for the changes in the maximum allowable delta frequencies that have a direct bearing on the IFRO calculation. In the 2016 and 2017 *Frequency Response Annual Analysis* reports, several inconsistencies with the behavior of the IFRO calculations for the relative changes in Values A and B and Point C.[22] Additional analysis of those inconsistencies is contained in this report.

CB_R is calculated as: $CB_R = \frac{Value\ A - Point\ C}{Value\ A - Value\ B}$

Table 2.5 through **Table 2.8** compare the CB_R values for 2018 for each Interconnection with the CB_R values from the *2017 Frequency Response Annual Analysis* report.

[19] Adjustment for the differences between Point C and Value B

[20] Base Delta Frequency/CB_R

[21] Adjustment for the event nadir being below the Value B (Eastern Interconnection only) due to primary frequency response withdrawal.

[22] See Findings section of the *2016 Frequency Response Annual Analysis*.

Table 2.5: Maximum Allowable Delta Frequency Comparison					
Eastern Interconnection	**OY 2018 In Use[23]**	**OY 2018 Calc.[24]**	**OY 2019 Calc.[25]**	**2018 Calc. to 2019 Calc. Change**	**Units**
Starting Frequency	59.974	59.974	59.974	0.000	Hz
Min. Frequency Limit	59.500	59.500	59.500	0.000	Hz
Base Delta Frequency	0.474	0.474	0.474	0.000	Hz
CB_R	1.052	1.111	1.134	0.023	Ratio
Delta Freq. (DF_{CBR})	0.450	0.427	0.418	-0.009	Hz
BC'_{ADJ}	0.007	0.007	0.006	-0.001	Hz
Max. Allowable Delta Frequency	**0.443**	**0.420**	**0.412**	**-0.008**	**Hz**

Table 2.6: Maximum Allowable Delta Frequency Comparison					
Western Interconnection	**OY 2018 In Use[24]**	**OY 2018 Calc.[25]**	**OY 2019 Calc.[26]**	**2018 Calc. to 2019 Calc. Change**	**Units**
Starting Frequency	59.967	59.967	59.966	-0.001	Hz
Min. Frequency Limit	59.500	59.500	59.500	0.000	Hz
Base Delta Frequency	0.467	0.467	0.466	-0.001	Hz
CB_R	1.598	1.670	1.879	0.209	Ratio
Delta Freq. (DF_{CBR})	0.292	0.280	0.248	-0.032	Hz
BC'_{ADJ}	N/A	N/A	N/A	N/A	Hz
Max. Allowable Delta Frequency	**0.292**	**0.280**	**0.248**	**-0.032**	**Hz**

[23] Calculated in the 2015 FRAA report. Average frequency values were for operating years 2012 through 2014.

[24] Calculated in the 2017 FRAA report. Average frequency values were for operating years 2013 through 2016.

[25] Calculated in the 2018 FRAA report. Average frequency values were for operating years 2014 through 2017.

Table 2.7: Maximum Allowable Delta Frequency Comparison					
ERCOT Interconnection	**OY 2017 In Use[26]**	**OY 2017 Calc.[27]**	**OY 2018 Calc.[28]**	**2017 Calc. to 2018 Calc. Change**	**Units**
Starting Frequency	59.966	59.967	59.968	0.001	Hz
Min. Frequency Limit	59.300	59.300	59.300	0.000	Hz
Base Delta Frequency	0.666	0.667	0.668	0.001	Hz
CB_R	1.619	1.648	1.774	0.126	Ratio
Delta Freq. (DF_{CBR})	0.411	0.405	0.377	-0.028	Hz
BC'_{ADJ}	N/A	N/A	N/A	N/A	Hz
Max. Allowable Delta Frequency	**0.411**	**0.410**	**0.405**	**-0.005**	**Hz**

Table 2.8: Maximum Allowable Delta Frequency Comparison					
Québec Interconnection	**OY 2017 In Use[27]**	**OY 2017 Calc.[28]**	**OY 2018 Calc.[29]**	**2017 Calc. to 2018 Calc. Change**	**Units**
Starting Frequency	59.969	59.968	59.967	-0.001	Hz
Min. Frequency Limit	58.500	58.500	58.500	0.000	Hz
Base Delta Frequency	1.469	1.468	1.467	-0.001	Hz
CB_R	1.550	1.550	1.550	0.000	Ratio
Delta Freq. (DF_{CBR})	0.948	0.947	0.946	0.000	Hz
BC'_{ADJ}	N/A	N/A	N/A	N/A	Hz
Max. Allowable Delta Frequency	**0.948**	**0.947**	**0.946**	**0.000**	**Hz**

[26] Calculated in the 2015 FRAA report. Average frequency values were for operating years 2012 through 2014.

[27] Calculated in the 2017 FRAA report. Average frequency values were for operating years 2013 through 2016.

[28] Calculated in the 2018 FRAA report. Average frequency values were for operating years 2014 through 2017.

Calculated IFROs

Table 2.9 shows the determination of IFROs for operating year 2019 (December 2018 through November 2019) under standard BAL-003-1 based on a resource loss equivalent to the recommended criteria in each Interconnection. The maximum allowable delta frequency values have already been modified to include the adjustments for the differences between Value B and Point C (CB_R), the differences in measurement of Point C using one-second and sub-second data (CC_{ADJ}), and the event nadir being below the Value B (BC'_{ADJ}).

Table 2.9: Initial Calculation of Operating Year 2019 IFROs

	Eastern (EI)	Western (WI)	ERCOT (TI)	Québec (QI)	Units
Starting Frequency	59.974	59.967	59.967	59.968	Hz
Max. Allowable Delta Frequency	0.418	0.248	0.377	0.946	Hz
Resource Contingency Protection Criteria	4,500	2,626	2,750	1,700	MW
Credit for Load Resources	N/A	120[29]	1,209	N/A	MW
IFRO	**-1,092**	**-1,010**	**-409**	**-180**	**MW/0.1 Hz**
Absolute Value of IFRO[30]	**1,092**	**1,010**	**409**	**180**	**MW/0.1 Hz**
Absolute Value of Mean Interconnection Frequency Response Performance for Operating Year 2017[31]	2,257	1,836	835	748	MW/0.1 Hz

Note: The operating year 2017 frequency response performance was significantly higher than the 2019 calculated IFROs for all four Interconnections.

Comparison to Previous IFRO Values

The IFROs were first calculated and presented in the *2012 Frequency Response Initiative Report*. Recommendations from that report called for an annual analysis and recalculation of the IFROs. Table 2.10 through Table 2.11 compare the current IFROs and their key component values to those presented in the *2016 Frequency Response Annual Analysis* report.

[29] Based on the most updated information regarding load shedding for loss of two Palo Verde units, with a Western Interconnection CLR = 120 MW.

[30] The values of IFRO calculated for operating year 2018 are shown here for reference. It is recommended that the IFROs for operating year 2019 remain the same as the values calculated in the 2015 FRAA report due to inconsistencies identified in the IFRO formulae, as described in the Recommendations and Findings sections of the report.

[31] Based on mean Interconnection frequency response performance from Appendix E of the *2018 State of Reliability* report for operating year 2017.

Table 2.10: Interconnection IFRO Comparison						
	OY 2018 In Use[32]	OY 2018 Calc.[33]	OY 2019 Calc.[34]	2018 Calc. to 2019 Calc. Change	OY 2018 In Use to 2019 Calc. Change	Units
Eastern Interconnection						
Starting Frequency	59.974	59.974	59.974	0	0	Hz
Max. Allowable Delta Frequency	0.443	0.420	0.412	-0.008	-0.031	Hz
Resource Contingency Protection Criteria	4,500	4,500	4,500	0	0	MW
Credit for Load Resources	N/A	N/A	N/A	N/A	N/A	MW
Absolute Value of IFRO	**1,015**	**1,071**	**1,092**	21	77	MW/0.1 Hz
Western Interconnection						
Starting Frequency	59.967	59.967	59.968	0.001	0.002	Hz
Max. Allowable Delta Frequency	0.292	0.280	0.248	-0.028	-0.034	Hz
Resource Contingency Protection Criteria	2,626	2,626	2,626	0	0	MW
Credit for Load Resources	120	120	120	0	0	MW
Absolute Value of IFRO	**858**	**895**	**1010**	115	152	MW/0.1 Hz
ERCOT Interconnection						
Starting Frequency	59.966	59.967	59.967	0.000	0.001	Hz
Max. Allowable Delta Frequency	0.411	0.410	0.405	-0.005	-0.006	Hz
Resource Contingency Protection Criteria	2,750	2,750	2,750	0	0	MW
Credit for Load Resources	1,181	1,209	1,209	28	0	MW
Absolute Value of IFRO	**381**	**380**	**381**	1	0	MW/0.1 Hz
Québec Interconnection						
Starting Frequency	59.969	59.968	59.967	-0.001	-0.002	Hz
Max. Allowable Delta Frequency	0.948	0.947	0.946	-0.001	-0.002	Hz
Resource Contingency Protection Criteria	1,700	1,700	1,700	0	0	MW
Credit for Load Resources	N/A	N/A	N/A	N/A	N/A	MW
Absolute Value of IFRO	**179**	**180**	**180**	0	1	MW/0.1 Hz

[32] Calculated in the 2015 FRAA report. Average frequency values were for operating years 2012 through 2014.
[33] Calculated in the 2017 FRAA report. Average frequency values were for operating years 2013 through 2016.
[34] Calculated in the 2018 FRAA report. Average frequency values were for operating years 2014 through 2017.

The calculated IFRO for the ERCOT Interconnection decreased by only 1 MW/0.1 Hz, and Québec Interconnection IFRO did not change, representing relatively stable frequency response characteristics over the time-period of events analyzed.

Recommended IFROs for Operating Year 2018

Due to inconsistencies outlined in this report, the IFRO values for operating year 2019 (December 2018 through November 2019) shall remain the same values as calculated in the *2015 FRAA* report for operating year 2016[35] and held constant through operating years 2017 and 2018, shown in **Table 2.11**.

Table 2.11: Recommended IFROs for Operating Year 2017

	Eastern (EI)	Western (WI)	ERCOT (TI)	Québec (QI)	Units
IFRO	**-1,015**	**-858**	**-381**	**-179**	**MW/0.1 Hz**

[35] These IFROs were held constant through operating years 2016, 2017, and 2018.

Chapter 3: Dynamics Analysis of Recommended IFROs

Because the IFROs for the Eastern, Western, and ERCOT Interconnections have not changed from those prescribed for operating year 2018 (1,015 MW/0.1 Hz, 858 MW/0.1 Hz, and 381 MW/0.1 Hz, respectively), additional dynamic validation analyses were not done for this report.

Refer to the dynamics validation in the *2017 Frequency Response Annual Analysis* report for details. No analysis was performed for the Québec Interconnection.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RR17-6-000**

COMPLIANCE FILING OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO ORDER APPROVING IN PART AND DENYING IN PART AMENDMENTS TO THE ELECTRIC RELIABILITY ORGANIZATION'S RULES OF PROCEDURE

The North American Electric Reliability Corporation ("NERC") hereby submits this compliance filing in accordance with the Federal Energy Regulatory Commission's ("Commission" or "FERC") July 19, 2018 Order ("Order") to comply with the Commission's directives in the Order to:

(i) submit a compliance within 120 days restoring Rule of Procedure Sections 603 (Examination and Maintenance of NERC System Operator Certification Credentials), 604 (Dispute Resolution Process) and 605 (Disciplinary Action), and

(ii) correct typographical errors in proposed Sections 600 and 900.

NERC respectfully requests that the Commission accept this filing as compliant with the Commission's directives in the Order.

Respectfully submitted,

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Date: November 16, 2018

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 16th day of November 2018.

/s/ Nina H. Jenkins-Johnston

Nina H. Jenkins-Johnston

Counsel for North American Electric Reliability Corporation

Attachment A
Clean version of Rules of Procedure
Sections 600 and 900

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rules of Procedure

Effective: [proposed date]

TABLE OF CONTENTS

SECTION 100 — APPLICABILITY OF RULES OF PROCEDURE 1

SECTION 200 — DEFINITIONS OF TERMS 2

SECTION 300 — RELIABILITY STANDARDS DEVELOPMENT 3

301. General 3
302. Essential Attributes for Technically Excellent Reliability Standards 3
303. Relationship between Reliability Standards and Competition 5
304. Essential Principles for the Development of Reliability Standards 5
305. Registered Ballot Body 6
306. Standards Committee 8
307. Standards Process Management 8
308. Steps in the Development of Reliability Standards 8
309. Filing of Reliability Standards for Approval by Applicable Governmental Authorities 9
310. Annual Reliability Standards Development Plan 10
311. Regional Entity Standards Development Procedures 10
312. Regional Reliability Standards 12
313. Other Regional Criteria, Guides, Procedures, Agreements, Etc. 15
314. Conflicts with Statutes, Regulations, and Orders 16
315. Revisions to NERC Standard Processes Manual 16
316. Accreditation 16
317. Periodic Review of Reliability Standards 16
318. Coordination with the North American Energy Standards Board 17
319. Archived Standards Information 17
320. Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels 17
321. Special Rule to Address Certain Regulatory Directives 18

SECTION 400 — COMPLIANCE ENFORCEMENT 22

401. Scope of the NERC Compliance Monitoring and Enforcement Program 22
402. NERC Oversight of the Regional Entity Compliance Monitoring and Enforcement Programs 25
403. Required Attributes of Regional Entity Compliance Monitoring and Enforcement Programs . 29
404. NERC Monitoring of Compliance for Regional Entities or Bulk Power Owners, Operator, or Users 37
405. Monitoring of Reliability Standards and Other Requirements Applicable to NERC 38
406. Independent Audits of the NERC Compliance Monitoring and Enforcement Program 39
407. Penalties, Sanctions, and Remedial Action Directives 39
408. Review of NERC Decisions 40
409. Appeals from Final Decisions of Hearing Bodies 41
410. Hold Harmless 42
411. Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards 43
412. Certification of Questions from Hearing Bodies for Decision by the NERC Board of Trustees Compliance Committee 43
413. Review and Processing of Hearing Body Final Decisions that Are Not Appealed 44
414. Appeals of Decisions of Hearing Bodies Granting or Denying Motions to Intervene in Hearing Body Proceedings 44

SECTION 500 — ORGANIZATION REGISTRATION AND CERTIFICATION 46

501. Scope of the Organization Registration and Organization Certification Programs 46
502. Organization Registration and Organization Certification Program Requirements 50
503. Regional Entity Implementation of Organization Registration and Organization Certification Program Requirements 52
504. Appeals 53
505. Program Maintenance 53
506. Independent Audit of NERC Organization Registration and Organization Certification Program 53
507. Provisions Relating to Joint Registration Organizations (JRO) 54
508. Provisions Relating to Coordinated Functional Registration (CFR) Entities 55
509. Exceptions to the Definition of the Bulk Electric System 56

SECTION 600 — PERSONNEL CERTIFICATION PROGRAM 57

601. Scope of Personnel Certification Program 57
602. Structure of ERO Personnel Certification Program 57
603. Examination and Maintenance of NERC System Operator Certification Credentials 57
604. Dispute Resolution Process 58
605. Disciplinary Action 60
606. Candidate Testing 62
607. Public Information About the Personnel Certification Program 62
608. Responsibilities to Applicants for Certification or Re-Certification 62
609. Responsibilities to Employers of Certified Personnel 62

SECTION 700 — RELIABILITY READINESS EVALUATION AND IMPROVEMENT AND FORMATION OF SECTOR FORUMS 64

701. Confidentiality Requirements for Readiness Evaluations and Evaluation Team Members 64
702. Formation of Sector Forum 64

SECTION 800 — RELIABILITY ASSESSMENT AND PERFORMANCE ANALYSIS 65

801. Objectives of the Reliability Assessment and Performance Analysis Program 65
802. Scope of the Reliability Assessment Program 65
803. Reliability Assessment Reports 66
804. Reliability Assessment Data and Information Requirements 67
805. Reliability Assessment Process 68
806. Scope of the Reliability Performance and Analysis Program 70
807. Analysis of Major Events 70
808. Analysis of Off-Normal Occurrences, Bulk Power System Performance, and Bulk Power System Vulnerabilities 71
809. Reliability Benchmarking 72
810. Information Exchange and Issuance of NERC Advisories, Recommendations and Essential Actions 72
811. Equipment Performance Data 73

SECTION 900 — TRAINING AND EDUCATION 74

901. Scope of the Training and Education Program 74
902. Continuing Education Program 74

SECTION 1000 — SITUATION AWARENESS AND INFRASTRUCTURE SECURITY 75

1001. Situation Awareness 75
1002. Reliability Support Services 75

1003. Infrastructure Security Program 76

SECTION 1100 — ANNUAL NERC BUSINESS PLANS AND BUDGETS 78

1101. Scope of Business Plans and Budgets 78
1102. NERC Funding and Cost Allocation 78
1103. NERC Budget Development 78
1104. Submittal of Regional Entity Budgets to NERC 79
1105. Submittal of NERC and Regional Entity Budgets to Governmental Authorities for Approval 79
1106. NERC and Regional Entity Billing and Collections 80
1107. Penalty Applications 81
1108. Special Assessments 82

SECTION 1200 — REGIONAL DELEGATION AGREEMENTS 83

1201. Pro Forma Regional Delegation Agreement 83
1202. Regional Entity Essential Requirements 83
1203. Negotiation of Regional Delegation Agreements 83
1204. Conformance to Rules and Terms of Regional Delegation Agreements 83
1205. Sub-delegation 83
1206. Nonconformance to Rules or Terms of Regional Delegation Agreement 83
1207. Regional Entity Audits 84
1208. Process for Considering Registered Entity Requests to Transfer to Another Regional Entity .. 84

SECTION 1300 — COMMITTEES 87

1301. Establishing Standing Committees 87
1302. Committee Membership 87
1303. Procedures for Appointing Committee Members 87
1304. Procedures for Conduct of Committee Business 87
1305. Committee Subgroups 88

SECTION 1400 — AMENDMENTS TO THE NERC RULES OF PROCEDURE 89

1401. Proposals for Amendment or Repeal of Rules of Procedure 89
1402. Approval of Amendment or Repeal of Rules of Procedure 89

SECTION 1500 — CONFIDENTIAL INFORMATION 90

1501. Definitions 90
1502. Protection of Confidential Information 90
1503. Requests for Information 91
1504. Employees, Contractors and Agents 93
1505. Provision of Information to FERC and Other Governmental Authorities 93
1506. Permitted Disclosures 93
1507. Remedies for Improper Disclosure 93

SECTION 1600 — REQUESTS FOR DATA OR INFORMATION 95

1601. Scope of a NERC or Regional Entity Request for Data or Information 95
1602. Procedure for Authorizing a NERC Request for Data or Information 95
1603. Owners, Operators, and Users to Comply 96
1604. Requests by Regional Entity for Data or Information 96
1605. Confidentiality 97
1606. Expedited Procedures for Requesting Time-Sensitive Data or Information 97

SECTION 1700 — CHALLENGES TO DETERMINATIONS 99

1701. Scope of Authority 99
1702. Challenges to Determinations by Planning Coordinators Under Reliability Standard PRC-023 99
1703. Challenges to NERC Determinations of BES Exception Requests Under Section 509 101

SECTION 100 — APPLICABILITY OF RULES OF PROCEDURE

NERC and NERC Members shall comply with these Rules of Procedure. Each Regional Entity shall comply with these Rules of Procedure as applicable to functions delegated to the Regional Entity by NERC or as required by an Applicable Governmental Authority or as otherwise provided.

Each Bulk Power System owner, operator, and user shall comply with all Rules of Procedure of NERC that are made applicable to such entities by approval pursuant to applicable legislation or regulation, or pursuant to agreement.

Any entity that is unable to comply or that is not in compliance with a NERC Rule of Procedure shall immediately notify NERC in writing, stating the Rule of Procedure of concern and the reason for not being able to comply with the Rule of Procedure.

NERC shall evaluate each case and inform the entity of the results of the evaluation. If NERC determines that a Rule of Procedure has been violated, or cannot practically be complied with, NERC shall notify the Applicable Governmental Authorities and take such other actions as NERC deems appropriate to address the situation.

NERC shall comply with each approved Reliability Standard that identifies NERC or the Electric Reliability Organization as a responsible entity. Regional Entities shall comply with each approved Reliability Standard that identifies Regional Entities as responsible entities. A violation by NERC or a Regional Entity of such a Reliability Standard shall constitute a violation of these Rules of Procedure.

SECTION 200 — DEFINITIONS OF TERMS

Definitions of terms used in the NERC Rules of Procedure are set forth in **Appendix 2**, *Definitions Used in the Rules of Procedure*.

SECTION 300 — RELIABILITY STANDARDS DEVELOPMENT

301. General

NERC shall develop and maintain Reliability Standards that apply to Bulk Power System owners, operators, and users and that enable NERC and Regional Entities to measure the reliability performance of Bulk Power System owners, operators, and users; and to hold them accountable for Reliable Operation of the Bulk Power Systems. The Reliability Standards shall be technically excellent, timely, just, reasonable, not unduly discriminatory or preferential, in the public interest, and consistent with other applicable standards of governmental authorities.

302. Essential Attributes for Technically Excellent Reliability Standards

1. **Applicability** — Each Reliability Standard shall clearly identify the functional classes of entities responsible for complying with the Reliability Standard, with any specific additions or exceptions noted. Such functional classes[1] include: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, market operators, Planning Authorities, Transmission Planners, Resource Planners, and Distribution Providers. Each Reliability Standard shall also identify the geographic applicability of the Reliability Standard, such as the entire North American Bulk Power System, an Interconnection, or within a Region. A Reliability Standard may also identify any limitations on the applicability of the Reliability Standard based on electric Facility characteristics.

2. **Reliability Objectives** — Each Reliability Standard shall have a clear statement of purpose that shall describe how the Reliability Standard contributes to the reliability of the Bulk Power System. The following general objectives for the Bulk Power System provide a foundation for determining the specific objective(s) of each Reliability Standard:

    2.1 **Reliability Planning and Operating Performance** — Bulk Power Systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.

    2.2 **Frequency and Voltage Performance** — The frequency and voltage of Bulk Power Systems shall be controlled within defined limits through the balancing of Real and Reactive Power supply and demand.

[1] These functional classes of entities are derived from NERC's Reliability Functional Model. When a Reliability Standard identifies a class of entities to which it applies, that class must be defined in the Glossary of Terms Used in NERC Reliability Standards.

2.3 **Reliability Information** — Information necessary for the planning and operation of reliable Bulk Power Systems shall be made available to those entities responsible for planning and operating Bulk Power Systems.

2.4 **Emergency Preparation** — Plans for emergency operation and system restoration of Bulk Power Systems shall be developed, coordinated, maintained, and implemented.

2.5 **Communications and Control** — Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of Bulk Power Systems.

2.6 **Personnel** — Personnel responsible for planning and operating Bulk Power Systems shall be trained and qualified, and shall have the responsibility and authority to implement actions.

2.7 **Wide-Area View** — The reliability of the Bulk Power Systems shall be assessed, monitored, and maintained on a Wide-Area basis.

2.8 **Security** — Bulk Power Systems shall be protected from malicious physical or cyber attacks.

3. **Performance Requirement or Outcome** — Each Reliability Standard shall state one or more performance Requirements, which if achieved by the applicable entities, will provide for a reliable Bulk Power System, consistent with good utility practices and the public interest. Each Requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for Bulk Power System reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability** — Each performance Requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that Requirement. Each performance Requirement shall have one or more associated measures used to objectively evaluate compliance with the Requirement. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance.

5. **Technical Basis in Engineering and Operations** — Each Reliability Standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.

6. **Completeness** — Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance.

7. **Consequences for Noncompliance** — In combination with guidelines for Penalties and sanctions, as well as other ERO and Regional Entity compliance

documents, the consequences of violating a Reliability Standard are clearly presented to the entities responsible for complying with the Reliability Standards.

8. **Clear Language** — Each Reliability Standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance.

9. **Practicality** — Each Reliability Standard shall establish Requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

10. **Consistent Terminology** — To the extent possible, Reliability Standards shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards development process.

303. Relationship between Reliability Standards and Competition

To ensure Reliability Standards are developed with due consideration of impacts on competition, to ensure Reliability Standards are not unduly discriminatory or preferential, and recognizing that reliability is an essential requirement of a robust North American economy, each Reliability Standard shall meet all of these market-related objectives:

1. **Competition** — A Reliability Standard shall not give any market participant an unfair competitive advantage.

2. **Market Structures** — A Reliability Standard shall neither mandate nor prohibit any specific market structure.

3. **Market Solutions** — A Reliability Standard shall not preclude market solutions to achieving compliance with that Reliability Standard.

4. **Commercially Sensitive Information** — A Reliability Standard shall not require the public disclosure of commercially sensitive information or other Confidential Information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with Reliability Standards.

5. **Adequacy** — NERC shall not set Reliability Standards defining an adequate amount of, or requiring expansion of, Bulk Power System resources or delivery capability.

304. Essential Principles for the Development of Reliability Standards

NERC shall develop Reliability Standards in accordance with the NERC *Standard Processes Manual*, which is incorporated into these Rules of Procedure as **Appendix 3A**. Appeals in connection with the development of a Reliability Standard shall also be conducted in accordance with the NERC *Standard Processes Manual*. Any amendments

or revisions to the *Standard Processes Manual* shall be consistent with the following essential principles:

1. **Openness** — Participation shall be open to all Persons and who are directly and materially affected by the reliability of the North American Bulk Power System. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in NERC or any other organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

2. **Transparency** — The process shall be transparent to the public.

3. **Consensus-building** —The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

4. **Fair Balance of Interests** — The process shall fairly balance interests of all stakeholders and shall not be dominated by any two Segments as defined in **Appendix 3D**, *Development of the Registered Ballot Body*, of these Rules of Procedure, and no single Segment, individual or organization shall be able to defeat a matter.

5. **Due Process** — Development of Reliability Standards shall provide reasonable notice and opportunity for any Person with a direct and material interest to express views on a proposed Reliability Standard and the basis for those views, and to have that position considered in the development of the Reliability Standards.

6. **Timeliness** — Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

305. Registered Ballot Body

NERC Reliability Standards shall be approved by a Registered Ballot Body prior to submittal to the Board and then to Applicable Governmental Authorities for their approval, where authorized by applicable legislation or agreement. This Section 305 sets forth the rules pertaining to the composition of, and eligibility to participate in, the Registered Ballot Body.

1. **Eligibility to Vote on Reliability Standards** — Any person or entity may join the Registered Ballot Body to vote on Reliability Standards, whether or not such person or entity is a Member of NERC.

2. **Inclusive Participation** — The Segment qualification guidelines are inclusive; i.e., any entity with a legitimate interest in the reliability of the Bulk Power

System that can meet any one of the eligibility criteria for a Segment is entitled to belong to and vote in each Segment for which it qualifies, subject to limitations defined in Sections 305.3 and 305.5.

3. **General Criteria for Registered Ballot Body Membership** — The general criteria for membership in the Segments are:

   3.1 **Multiple Segments** — A corporation or other organization with integrated operations or with affiliates that qualifies to belong to more than one Segment (e.g., Transmission Owners and Load-Serving Entities) may join once in each Segment for which it qualifies, provided that each Segment constitutes a separate membership and the organization is represented in each Segment by a different representative. Affiliated entities are collectively limited to one membership in each Segment for which they are qualified.

   3.2 **Withdrawing from a Segment or Changing Segments** — After its initial registration in a Segment, each registered participant may elect to withdraw from a Segment or apply to change Segments at any time.

   3.3 **Review of Segment Criteria** — The Board shall review the qualification guidelines and rules for joining Segments at least every three years to ensure that the process continues to be fair, open, balanced, and inclusive. Public input will be solicited in the review of these guidelines.

4. **Proxies for Voting on Reliability Standards** — Any registered participant may designate an agent or proxy to vote on its behalf. There are no limits on how many proxies an agent may hold. However, for the proxy to be valid, NERC must have in its possession written documentation signed by the representative of the registered participant that the voting right by proxy has been transferred from the registered participant to the agent.

5. **Segments** — The specific criteria for membership in each Registered Ballot Body Segment are defined in the *Development of the Registered Ballot Body* in **Appendix 3D.**

6. **Review of Segment Entries** — NERC shall review all applications for joining the Registered Ballot Body, and shall make a determination of whether the applicant's self-selection of a Segment satisfies at least one of the guidelines to belong to that Segment. The entity shall then become eligible to participate as a voting member of that Segment. The Standards Committee shall resolve disputes regarding eligibility for membership in a Segment, with the applicant having the right of appeal to the Board.

306. Standards Committee

The Standards Committee shall provide oversight of the Reliability Standards development process to ensure stakeholder interests are fairly represented. The Standards Committee shall not under any circumstance change the substance of a draft or approved Reliability Standard.

1. **Membership** — The Standards Committee is a representative committee comprising representatives of two members of each of the Segments in the Registered Ballot Body and two officers elected to represent the interests of the industry as a whole.

2. **Elections** — Standards Committee members are elected for staggered (one per Segment per year) two-year terms by the respective Segments in accordance with the *Procedure for the Election of Members of the NERC Standards Committee*, which is incorporated into these Rules of Procedure as **Appendix 3B**. Segments may use their own election procedure if such a procedure is ratified by two-thirds of the members of a Segment and approved by the Board.

3. **Canadian Representation**

   The Standards Committee will include Canadian representation as provided in **Appendix 3B**, *Procedure for the Election of Members of the NERC Standards Committee*.

4. **Open Meetings** — All meetings of the Standards Committee shall be open and publicly noticed on the NERC website.

307. Standards Process Management

NERC shall assign a standards process manager to administer the development of continent-wide Reliability Standards and a regional standards manager to administer the development of Regional Reliability Standards. The standards process manager shall be responsible for ensuring that the development and revision of Reliability Standards are in accordance with the NERC *Standard Processes Manual*. The standards process manager and the regional standards manager shall work to achieve the highest degree of integrity and consistency of quality and completeness of the Reliability Standards. The regional standards manager shall coordinate with any Regional Entities that develop Regional Reliability Standards to ensure those Regional Reliability Standards are effectively integrated with the NERC Reliability Standards.

308. Steps in the Development of Reliability Standards

1. **Procedure** — NERC shall develop Reliability Standards through the process set forth in the NERC *Standard Processes Manual* (**Appendix 3A**). The *Standard Processes Manual* includes provisions for developing Reliability Standards that can be completed using expedited processes, including a process to develop Reliability Standards to address national security situations that involve confidential issues.

2. **Board Adoption** — Reliability Standards or revisions to Reliability Standards approved by the ballot pool in accordance with the *Standard Processes Manual* shall be submitted for adoption by the Board. No Reliability Standard or revision to a Reliability Standard shall be effective unless adopted by the Board.

3. **Governmental Approval** — After Board adoption, a Reliability Standard or revision to a Reliability Standard shall be submitted to all Applicable Governmental Authorities in accordance with Section 309. No Reliability Standard or revision to a Reliability Standard shall be effective within a geographic area over which an Applicable Governmental Authority has jurisdiction unless it is approved by such Applicable Governmental Authority or is otherwise made effective pursuant to the laws applicable to such Applicable Governmental Authority.

309. Filing of Reliability Standards for Approval by Applicable Governmental Authorities

1. **Filing of Reliability Standards for Approval** — Where authorized by applicable legislation or agreement, NERC shall file with the Applicable Governmental Authorities each Reliability Standard, modification to a Reliability Standard, or withdrawal of a Reliability Standard that is adopted by the Board. Each filing shall be in the format required by the Applicable Governmental Authority and shall include: a concise statement of the basis and purpose of the Reliability Standard; the text of the Reliability Standard; the implementation plan for the Reliability Standard; a demonstration that the Reliability Standard meets the essential attributes of Reliability Standards as stated in Section 302; the drafting team roster; the ballot pool and final ballot results; and a discussion of public comments received during the development of the Reliability Standard and the consideration of those comments.

2. **Remanded Reliability Standards and Directives to Develop Standards** — If an Applicable Governmental Authority remands a Reliability Standard to NERC or directs NERC to develop a Reliability Standard, NERC shall within five (5) business days notify all other Applicable Governmental Authorities, and shall within thirty (30) calendar days report to all Applicable Governmental Authorities a plan and timetable for modification or development of the Reliability Standard. Reliability Standards that are remanded or directed by an Applicable Governmental Authority shall be modified or developed using the *Standard Processes Manual*. NERC shall, during the development of a modification for the remanded Reliability Standard or directed Reliability Standard, consult with other Applicable Governmental Authorities to coordinate any impacts of the proposed Reliability Standards in those other jurisdictions. The expedited standards development process may be applied if necessary to meet a timetable for action required by the Applicable Governmental Authorities, respecting to the extent possible the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interest in developing Reliability Standards. If the Board of

Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply.

3. **Directives to Develop Reliability Standards under Extraordinary Circumstances** — An Applicable Governmental Authority may, on its own initiative, determine that extraordinary circumstances exist requiring expedited development of a Reliability Standard. In such a case, the Applicable Governmental Authority may direct the development of a Reliability Standard within a certain deadline. NERC staff shall prepare the Standards Authorization Request. The proposed Reliability Standard will then proceed through the Reliability Standards development process, using the expedited action process described in the *Standard Processes Manual* as necessary to meet the specified deadline. The timeline will be developed to respect, to the extent possible, the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards. If the Board of Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply, with appropriate modification of the timeline.

310. Annual Reliability Standards Development Plan

NERC shall develop and provide an annual Reliability Standards Development Plan for development of Reliability Standards to the Applicable Governmental Authorities. NERC shall consider the comments and priorities of the Applicable Governmental Authorities in developing and updating the annual Reliability Standards Development Plan. Each annual Reliability Standards Development Plan shall include a progress report comparing results achieved to the prior year's Reliability Standards Development Plan.

311. Regional Entity Standards Development Procedures

1. **NERC Approval of Regional Entity Reliability Standards Development Procedure** — To enable a Regional Entity to develop Regional Reliability Standards that are to be recognized and made part of NERC Reliability Standards, a Regional Entity may request NERC to approve a Regional Reliability Standards development procedure.

2. **Public Notice and Comment on Regional Reliability Standards Development Procedure** — Upon receipt of such a request, NERC shall publicly notice and request comment on the proposed Regional Reliability Standards development procedure, allowing a minimum of 45 days for comment. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to withdraw the request, revise the Regional Reliability Standards development procedure and request another posting for comment, or submit the

Regional Reliability Standards development procedure, along with its consideration of any objections received, for approval by NERC.

3. **Evaluation of Regional Reliability Standards Development Procedure** — NERC shall evaluate whether a Regional Reliability Standards development procedure meets the criteria listed below and shall consider stakeholder comments, any unresolved stakeholder objections, and the consideration of comments provided by the Regional Entity, in making that determination. If NERC determines the Regional Reliability Standards development procedure meets these requirements, the Regional Reliability Standards development procedure shall be submitted to the Board for approval. The Board shall consider the recommended action, stakeholder comments, any unresolved stakeholder comments, and the Regional Entity consideration of comments in determining whether to approve the Regional Reliability Standards development procedure.

   3.1 **Evaluation Criteria** — The Regional Reliability Standards development procedure shall be:

      3.1.1 **Open** — The Regional Reliability Standards development procedure shall provide that any person or entity who is directly and materially affected by the reliability of the Bulk Power Systems within the Regional Entity shall be able to participate in the development and approval of Reliability Standards. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in the Regional Entity, a Regional Entity or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

      3.1.2 **Inclusive** — The Regional Reliability Standards development procedure shall provide that any Person with a direct and material interest has a right to participate by expressing an opinion and its basis, having that position considered, and appealing through an established appeals process if adversely affected.

      3.1.3 **Balanced** — The Regional Reliability Standards development procedure shall have a balance of interests and shall not permit any two interest categories to dominate a matter or any single interest category to defeat a matter.

      3.1.4 **Due Process** — The Regional Reliability Standards development procedure shall provide for reasonable notice and opportunity for public comment. At a minimum, the Regional Reliability Standards development procedure shall include public notice of the intent to develop a Regional Reliability Standard, a public comment period on the proposed Regional Reliability Standard,

due consideration of those public comments, and a ballot of interested stakeholders.

3.1.5 **Transparent** — All actions material to the development of Regional Reliability Standards shall be transparent. All Regional Reliability Standards development meetings shall be open and publicly noticed on the Regional Entity's website.

3.1.6 **Accreditation of Regional Standards Development Procedure** — A Regional Entity's Regional Reliability Standards development procedure that is accredited by the American National Standards Institute shall be deemed to meet the criteria listed in this Section 311.3.1, although such accreditation is not a prerequisite for approval by NERC.

3.1.7 **Use of NERC Procedure** — A Regional Entity may adopt the NERC *Standard Processes Manual* as the Regional Reliability Standards development procedure, in which case the Regional Entity's Regional Reliability Standards development procedure shall be deemed to meet the criteria listed in this Section 311.3.1.

4. **Revisions of Regional Reliability Standards Development Procedures** — Any revision to a Regional Reliability Standards development procedure shall be subject to the same approval requirements set forth in Sections 311.1 through 311.3.

5. **Duration of Regional Reliability Standards Development Procedures** — The Regional Reliability Standards development procedure shall remain in effect until such time as it is replaced with a new version approved by NERC or it is withdrawn by the Regional Entity. The Regional Entity may, at its discretion, withdraw its Regional Reliability Standards development procedure at any time.

312. Regional Reliability Standards

1. **Basis for Regional Reliability Standards** — 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. Such Regional Reliability Standards shall in all cases be submitted to NERC for adoption and, if adopted, made part of the NERC Reliability Standards and shall be enforceable in accordance with the delegation agreement between NERC and the Regional Entity or other instrument granting authority over enforcement to the Regional Entity. No entities other than NERC and the Regional Entity shall be permitted to develop Regional Reliability Standards that are enforceable under statutory authority delegated to NERC and the Regional Entity.

2. **Regional Reliability Standards That are Directed by a NERC Reliability Standard** — Although it is the intent of NERC to promote uniform Reliability

Standards across North America, in some cases it may not be feasible to achieve a reliability objective with a Reliability Standard that is uniformly applicable across North America. In such cases, NERC may direct Regional Entities to develop Regional Reliability Standards necessary to implement a NERC Reliability Standard. Such Regional Reliability Standards that are developed pursuant to a direction by NERC shall be made part of the NERC Reliability Standards.

3. **Procedure for Developing an Interconnection-wide Regional Standard** — A Regional Entity organized on an Interconnection-wide basis may propose a Regional Reliability Standard for approval as a NERC Reliability Standard to be made mandatory for all applicable Bulk Power System owners, operators, and users within that Interconnection.

   3.1 **Presumption of Validity** — An Interconnection-wide Regional Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities, shall be adopted as a NERC Reliability Standard. NERC shall rebuttably presume that a Regional Reliability Standard developed, in accordance with a Regional Reliability Standards development process approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities.

   3.2 **Notice and Comment Procedure for Interconnection-wide Regional Reliability Standard** — NERC shall publicly notice and request comment on the proposed Interconnection-wide Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to comment on or withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for approval by NERC.

   3.3 **Adoption of Interconnection-wide Regional Reliability Standard by NERC** — NERC shall evaluate and recommend whether a proposed Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections that could serve as a basis for rebutting the presumption of validity of the Regional Reliability Standard. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning the proposed Regional Reliability Standard, shall have the option of

presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, NERC's recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

3.4 **Applicable Governmental Authority Approval** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

3.5 **Enforcement of Interconnection-wide Regional Reliability Standard** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

4. **Procedure for Developing Non-Interconnection-Wide Regional Reliability Standards** — Regional Entities that are not organized on an Interconnection-wide basis may propose Regional Reliability Standards to apply within their respective Regions. Such Regional Reliability Standards may be developed through the NERC Reliability Standards development procedure, or alternatively, through a Regional Reliability Standards development procedure that has been approved by NERC.

4.1 **No Presumption of Validity** — Regional Reliability Standards that are not proposed to be applied on an Interconnection-wide basis are not presumed to be valid but may be demonstrated by the proponent to be valid.

4.2 **Notice and Comment Procedure for Non-Interconnection-wide Regional Reliability Standards** — NERC shall publicly notice and request comment on the proposed Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to comment on or resolve any objections identified in the comments and may choose to withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for adoption by NERC.

4.3 **NERC Adoption of Non-Interconnection-wide Regional Reliability Standards** — NERC shall evaluate and recommend whether a proposed non-Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, the recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

4.4 **Applicable Governmental Authority Approval** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

4.5 **Enforcement of Non-Interconnection-wide Regional Reliability Standards** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

5. **Appeals** — A Regional Entity shall have the right to appeal NERC's decision not to adopt a proposed Regional Reliability Standard or Variance to the Commission or other Applicable Governmental Authority.

313. Other Regional Criteria, Guides, Procedures, Agreements, Etc.

1. **Regional Criteria** — 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. Regional Criteria may include specific acceptable 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 authority delegated by NERC pursuant to delegation agreements and do not require NERC approval.

2. **Catalog of Regional Criteria** — NERC shall maintain a current catalog of Regional Criteria. Regional Entities shall provide a catalog listing of Regional Criteria to NERC and shall notify NERC of changes to the listing. Regional Entities shall provide any listed document to NERC upon written request.

314. Conflicts with Statutes, Regulations, and Orders

Notice of Potential Conflict — If a Bulk Power System owner, operator, or user determines that a NERC or Regional Reliability Standard may conflict with a function, rule, order, tariff, rate schedule, legislative requirement or agreement that has been accepted, approved, or ordered by a governmental authority affecting that entity, the entity shall expeditiously notify the governmental authority, NERC, and the relevant Regional Entity of the conflict.

1. **Determination of Conflict —** NERC, upon request of the governmental authority, may advise the governmental authority regarding the conflict and propose a resolution of the conflict, including revision of the Reliability Standard if appropriate.

2. **Regulatory Precedence** — Unless otherwise ordered by a governmental authority, the affected Bulk Power System owner, operator, or user shall continue to follow the function, rule, order, tariff, rate schedule, legislative requirement, or agreement accepted, approved, or ordered by the governmental authority until the governmental authority finds that a conflict exists and orders a remedy and such remedy is affected.

315. Revisions to NERC Standard Processes Manual

Any person or entity may submit a written request to modify NERC *Standard Processes Manual*. Consideration of the request and development of the revision shall follow the process defined in the NERC *Standard Processes Manual*. Upon approval by the Board, the revision shall be submitted to the Applicable Governmental Authorities for approval. Changes shall become effective only upon approval by the Applicable Governmental Authorities or on a date designated by the Applicable Governmental Authorities or as otherwise applicable in a particular jurisdiction.

316. Accreditation

NERC shall seek and maintain accreditation of the NERC Reliability Standards development process by the American National Standards Institute.

317. Periodic Review of Reliability Standards

NERC shall complete a periodic review of each NERC Reliability Standard in accordance with the NERC *Standard Processes Manual*. The standards process manager shall be responsible for administration of the periodic review of Reliability Standards. As a result of this review, the NERC Reliability Standard shall be reaffirmed, revised, or withdrawn. If the review indicates a need to revise or withdraw the Reliability Standard, a request for revision or withdrawal shall be prepared, submitted and addressed in accordance with the NERC *Standard Processes Manual*.

318. Coordination with the North American Energy Standards Board

NERC shall maintain a close working relationship with the North American Energy Standards Board and ISO/RTO Council to ensure effective coordination of wholesale electric business practice standards and market protocols with the NERC Reliability Standards.

319. Archived Standards Information

NERC shall maintain a historical record of Reliability Standards information that is no longer maintained on-line. For example, Reliability Standards that have been retired may be removed from the on-line system. Archived information shall be retained indefinitely as practical, but in no case less than six years or one complete Reliability Standards review cycle from the date on which the Reliability Standard was no longer in effect. Archived records of Reliability Standards information shall be available electronically within 30 days following the receipt by the NERC standards information manager of a written request.

320. Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels

1. **Development of Violation Risk Factors and Violation Severity Levels** — NERC shall follow the process for developing Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) as set forth in the Standard Processes Manual, Appendix 3A to these Rules of Procedure.

2. **Remands of Directed Revision of VRFs and VSLs by Applicable Governmental Authorities** — If an Applicable Governmental Authority remands or directs a revision to a Board-approved VRF or VSL assignment, the NERC director of standards, after consulting with the standard drafting team, Standards Committee, and the NERC director of compliance operations, will recommend to the Board one of the following actions: (1) filing a request for clarification; (2) filing for rehearing or for review of the Applicable Governmental Authority decision; or (3) approval of the directed revisions to the VRF or VSL. If and to the extent time is available prior to the deadline for the Board's decision, an opportunity for interested parties to comment on the action taken will be provided.

3. **Alternative Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels** — In the event the Reliability Standards development process fails to produce Violation Risk Factors or Violation Severity Levels for a particular Reliability Standard in a timely manner, the Board of Trustees may approve Violation Risk Factors or Violation Severity Levels for that Reliability Standard after notice and opportunity for comment. In approving VRFs and VSLs, the Board shall consider the inputs of the Member Representatives Committee, affected stakeholders and NERC staff.

321. Special Rule to Address Certain Regulatory Directives

In circumstances where this Rule 321 applies, the Board of Trustees shall have the authority to take one or more of the actions set out below. The Board of Trustees shall have the authority to choose which one or more of the actions are appropriate to the circumstances and need not take these actions in sequential steps.

1. The Standards Committee shall have the responsibility to ensure that standards drafting teams address specific matters that are identified in directives issued by Applicable Governmental Authorities. If the Board of Trustees is presented with a proposed Reliability Standard that fails to address such directives, the Board of Trustees has the authority to remand, with instructions (including establishing a timetable for action), the proposed Reliability Standard to the Standards Committee.

2. Upon a written finding by the Board of Trustees that a ballot pool has failed to approve a proposed Reliability Standard that contains a provision to address a specific matter identified in a directive issued by an Applicable Governmental Authority, the Board of Trustees has the authority to remand the proposed Reliability Standard to the Standards Committee, with instructions to (i) convene a public technical conference to discuss the issues surrounding the regulatory directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified; (ii) working with NERC staff, prepare a memorandum discussing the issues, an analysis of the alternatives considered and other appropriate matters; and (iii) re-ballot the proposed Reliability Standard one additional time, with such adjustments in the schedule as are necessary to meet the deadline contained in paragraph 2.1 of this Rule.

    2.1 Such a re-ballot shall be completed within forty-five (45) days of the remand. The Standards Committee memorandum shall be included in the materials made available to the ballot pool in connection with the re-ballot.

    2.2 In any such re-ballot, negative votes without comments related to the proposal shall be counted for purposes of establishing a quorum, but only affirmative votes and negative votes with comments related to the proposal shall be counted for purposes of determining the number of votes cast and whether the proposed Reliability Standard has been approved.

3. If the re-balloted proposed Reliability Standard achieves at least an affirmative two-thirds majority vote of the weighted Segment votes cast, with a quorum established, then the proposed Reliability Standard shall be deemed approved by the ballot pool and shall be considered by the Board of Trustees for approval.

4. If the re-balloted proposed Reliability Standard fails to achieve at least an affirmative two-thirds majority vote of the weighted Segment votes cast, but does

achieve at least a sixty percent affirmative majority of the weighted Segment votes cast, with a quorum established, then the Board of Trustees has the authority to consider the proposed Reliability Standard for approval under the following procedures:

4.1 The Board of Trustees shall issue notice of its intent to consider the proposed Reliability Standard and shall solicit written public comment particularly focused on the technical aspects of the provisions of the proposed Reliability Standard that address the specific matter identified in the regulatory directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified.

4.2 The Board of Trustees may, in its discretion, convene a public technical conference to receive additional input on the matter.

4.3 After considering the developmental record, the comments received during balloting and the additional input received under paragraphs 4.1 and 4.2 of this Rule, the Board of Trustees has authority to act on the proposed Reliability Standard.

4.3.1 If the Board of Trustees finds that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to approve the proposed Reliability Standard and direct that it be filed with Applicable Governmental Authorities with a request that it be made effective.

4.3.2 If the Board of Trustees is unable to find that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to treat the proposed Reliability Standard as a draft Reliability Standard and direct that the draft Reliability Standard and complete developmental record, including the additional input received under paragraphs 4.1 and 4.2 of this Rule, be filed with the Applicable Governmental Authorities as a compliance filing in response to the order giving rise to the regulatory directive, along with a recommendation that the Reliability Standard not be made effective and an explanation of the basis for the recommendation.

5. Upon a written finding by the Board of Trustees that standard drafting team has failed to develop, or a ballot pool has failed to approve, a proposed Reliability

Standard that contains a provision to address a specific matter identified in a directive issued by an Applicable Governmental Authority, the Board of Trustees has the authority to direct the Standards Committee (with the assistance of stakeholders and NERC staff) to prepare a draft Reliability Standard that addresses the regulatory directive, taking account of the entire developmental record pertaining to the matter. If the Standards Committee fails to prepare such draft Reliability Standard, the Board of Trustees may direct NERC management to prepare such draft Reliability Standard.

5.1 The Board of Trustees may, in its discretion, convene a public technical conference to receive input on the matter. The draft Reliability Standard shall be posted for a 45-day public comment period.

5.2 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees finds that the draft Reliability Standard, with such modifications as the Board of Trustees determines are appropriate in light of the comments received, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to approve the draft Reliability Standard and direct that the proposed Reliability Standard be filed with Applicable Governmental Authorities with a request that the proposed Reliability Standard be made effective.

5.3 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees is unable to find that the draft Reliability Standard, even with modifications, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to direct that the draft Reliability Standard and complete developmental record be filed as a compliance filing in response to the regulatory directive with the Applicable Governmental Authority issuing the regulatory directive, with a recommendation that the draft Reliability Standard not be made effective.

5.4 The filing of the Reliability Standard under either paragraph 5.2 or paragraph 5.3 of this Rule shall include an explanation of the basis for the decision by the Board of Trustees.

5.5 A Reliability Standard approved under paragraph 5 of this Rule shall not be eligible for submission as an American National Standard.

6. NERC shall on or before March 31st of each year file a report with Applicable Governmental Authorities on the status and timetable for addressing each outstanding directive to address a specific matter received from an Applicable Governmental Authority.

SECTION 400 — COMPLIANCE ENFORCEMENT

401. Scope of the NERC Compliance Monitoring and Enforcement Program

1. **Components of the NERC Compliance Monitoring and Enforcement Program** — NERC shall develop and implement a NERC Compliance Monitoring and Enforcement Program to promote the reliability of the Bulk Power System by enforcing compliance with approved Reliability Standards in those regions of North American in which NERC and/or a Regional Entity (pursuant to a delegation agreement with NERC that has been approved by the Applicable Governmental Authority) has been given enforcement authority. There are four distinct parts of the NERC Compliance Monitoring and Enforcement Program: (1) NERC's oversight of the Regional Entity Compliance Monitoring and Enforcement Programs (Section 402), (2) the definition of the required Regional Entity Compliance Monitoring and Enforcement Program attributes (Section 403), (3) NERC's monitoring of Regional Entity compliance with Reliability Standards (Section 404), and (4) the monitoring of compliance with Reliability Standards that are applicable to NERC (Sections 405–406).

2. **Who Must Comply** — Where required by applicable legislation, regulation, rule or agreement, all Bulk Power System owners, operators, and users, Regional Entities, and NERC, are required to comply with all approved NERC Reliability Standards at all times. Regional Reliability Standards and Variances approved by NERC and the Applicable Governmental Authority shall be considered NERC Reliability Standards and shall apply to all Bulk Power System owners, operators, or users responsible for meeting those Reliability Standards within the Regional Entity boundaries, whether or not the Bulk Power System owner, operator, or user is a member of the Regional Entity.

3. **Data Access** — All Bulk Power System owners, operators, and users shall provide to NERC and the applicable Regional Entity such information as is necessary to monitor compliance with the Reliability Standards. NERC and the applicable Regional Entity will define the data retention and reporting requirements in the Reliability Standards and compliance reporting procedures.

4. **Role of Regional Entities in the Compliance Monitoring and Enforcement Program** — Each Regional Entity that has been delegated authority through a delegation agreement or other legal instrument approved by the Applicable Governmental Authority shall, in accordance with the terms of the approved delegation agreement, administer a Regional Entity Compliance Monitoring and Enforcement program to meet the NERC Compliance Monitoring and Enforcement Program goals and the requirements in this Section 400.

5. **Program Continuity** — NERC will ensure continuity of compliance monitoring and enforcement within the geographic boundaries of a Regional Entity in the event that NERC does not have a delegation agreement, or the Regional Entity withdraws from the agreement or does not operate its Compliance Monitoring and

Enforcement Program in accordance with the delegation agreement or other applicable requirements.

5.1 Should NERC not have a delegation agreement with a Regional Entity covering a geographic area, or a Regional Entity withdraws from an existing delegation agreement or the delegation agreement is otherwise terminated, NERC will directly administer the Compliance Monitoring and Enforcement Program applicable to owners, operators and users of the Bulk Power System within that geographic area.

1. This monitoring and enforcement will be accomplished by NERC and Compliance Staff from another approved Regional Entity.

2. If an existing delegation agreement with a Regional Entity is terminating, the Regional Entity shall promptly provide to NERC all relevant compliance information regarding Registered Entities, contacts, prior compliance information and actions, Mitigation Plans, and Remedial Action Directives for the period in which the Regional Entity was responsible for administering the Compliance Monitoring and Enforcement Program.

3. NERC will levy and collect all Penalties directly and will utilize any Penalty monies collected to offset the expenses of administering the Compliance Monitoring and Enforcement Program for the geographic area.

5.2 Should a Regional Entity seek to withdraw from its delegation agreement, NERC will seek agreement from another Regional Entity to amend its delegation agreement with NERC to extend that Regional Entity's boundaries for compliance monitoring and enforcement. In the event no Regional Entity is willing to accept this responsibility, NERC will administer the Compliance Monitoring and Enforcement Program within the geographical boundaries of the Regional Entity seeking to withdraw from the delegation agreement, in accordance with Section 401.5.1.

6. **Risk Elements** — NERC, with input from the Regional Entities, stakeholders, and regulators, shall at least annually identify risk elements to prioritize risks to the reliability of the Bulk Power System. These risk elements and related NERC Reliability Standards and Requirements are to be considered for compliance oversight in the annual NERC Compliance Monitoring and Enforcement Program Implementation Plan. NERC identifies the risk elements using data including, but not limited to: compliance findings; event analysis experience; data analysis; and the expert judgment of NERC and Regional Entity staff, committees, and subcommittees. NERC uses these risk elements to identify and prioritize interconnection and continent-wide risks to the reliability of the Bulk Power System. These identified risks, as well as risks to the reliability of the Bulk Power System identified by Regional Entities for their footprint, represent the

focus for monitoring activities in the upcoming year, and become inputs for developing oversight plans for individual Registered Entities. Compliance is required, and NERC and the Regional Entities have authority to monitor compliance, with all applicable NERC Reliability Standards whether or not they are identified as areas of focus to be considered for compliance oversight in the annual NERC Compliance Monitoring and Enforcement Program Implementation Plan or are included in a Regional Entity's oversight plan for the Registered Entity.

7. **Penalties, Sanctions, and Remedial Action Directives** — NERC and Regional Entities will apply Penalties, sanctions, and Remedial Action Directives that bear a reasonable relation to the seriousness of a violation and take into consideration timely remedial efforts as defined in the NERC *Sanction Guidelines*, which is incorporated into these rules as **Appendix 4B**.

8. **Multiple Enforcement Actions** – A Registered Entity shall not be subject to an enforcement action by NERC and a Regional Entity, or by more than one Regional Entity (unless the Registered Entity is registered in more than one Region in which the violation occurred), for the same violation.

9. **Records** — NERC shall maintain a record of each compliance submission, including Self-Reported, Possible, Alleged, and Confirmed Violations of approved Reliability Standards; associated Penalties, sanctions, Remedial Action Directives and settlements; and the status of mitigation actions.

10. **Confidential Information** — NERC will treat all Possible and Alleged Violations of Reliability Standards and matters related to a Compliance Monitoring and Enforcement Program process, including the status of any Compliance Investigation or other Compliance Monitoring and Enforcement Program process, as confidential in accordance with Section 1500.

    The types of information that will be considered confidential and will not (subject to statutory and regulatory requirements) be disclosed in any public information reported by NERC are identified in Section 1500. Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident, will be identified and protected from public disclosure as Critical Energy Infrastructure Information in accordance with Section 1500.

    The Regional Entity and NERC shall give Bulk Power System owners, operators, and users a reasonable opportunity to demonstrate that information concerning a violation is confidential before such report is disclosed to the public.

11. **Public Posting** — When the affected Bulk Power System owner, operator, or user either agrees with a Possible or Alleged Violation(s) of a Reliability Standard(s) or a report of a Compliance Audit or Compliance Investigation, or enters into a settlement agreement concerning a Possible or Alleged Violation(s), or the time for submitting an appeal is passed, or all appeals processes are complete, NERC

shall, subject to the confidentiality requirements of these Rules of Procedure, publicly post each Confirmed Violation, Penalty or sanction, settlement agreement, and final Compliance Audit or Compliance Investigation report, on its website. As required by an Applicable Governmental Authority, NERC will also post information concerning noncompliance disposed of as Compliance Exceptions, subject to Section 1500 of these Rules of Procedures.

11.1 Each Bulk Power System owner, operator, or user may provide NERC with a statement to accompany the Confirmed Violation or report to be posted publicly. The statement must be on company letterhead and include a signature, as well as the name and title of the person submitting the information.

11.2 In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information (*NERC Security Guidelines for the Electricity Sector — Protecting Potentially Sensitive Information* may be used as a guide) or other Confidential Information shall be redacted in accordance with Section 1500 and not be released publicly.

11.3 Subject to redaction of Critical Energy Infrastructure Information or other Confidential Information, for each Confirmed Violation or settlement relating to a Possible Violation or an Alleged Violation, the public posting shall include the name of any relevant entity, the nature, time period, and circumstances of such Possible, Alleged or Confirmed Violation, any Mitigation Plan or other Mitigating Activities to be implemented by the Registered Entity in connection with the Confirmed Violation or settlement, and sufficient facts to assist owners, operators and users of the Bulk Power System to evaluate whether they have engaged in or are engaging in similar activities.

12. **Violation Information Review** — NERC Compliance Staff shall periodically review and analyze all reports of Possible, Alleged and Confirmed Violations to identify trends and other pertinent reliability issues.

402. NERC Oversight of the Regional Entity Compliance Monitoring and Enforcement Programs

1. **NERC Monitoring Program** — NERC shall have a program to monitor the Compliance Monitoring and Enforcement Program of each Regional Entity that has been delegated authority. The objective of this monitoring program shall be to ensure that the Regional Entity carries out its Compliance Monitoring and Enforcement Program in accordance with these Rules of Procedure and the terms of the delegation agreement, and to ensure consistency and fairness of the Regional Entity's Compliance Monitoring and Enforcement Program. Oversight and monitoring by NERC shall be accomplished through an annual Compliance Monitoring and Enforcement Program review, program audits, and regular

evaluations of Regional Entity Compliance Monitoring and Enforcement Program performance as described below.

1.1 **NERC Review of Annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plans** — NERC shall require each Regional Entity to submit for review and approval an annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan. NERC shall review each annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan and shall accept the plan if it meets NERC requirements and the requirements of the delegation agreement.

1.2 **Regional Entity Compliance Monitoring and Enforcement Program Evaluation** — NERC shall annually evaluate the goals, tools, and procedures of each Regional Entity Compliance Monitoring and Enforcement Program to determine the effectiveness of each Regional Entity Compliance Monitoring and Enforcement Program, using criteria developed by the NERC Compliance and Certification Committee.

1.3 **Regional Entity Compliance Monitoring and Enforcement Program Audit** — At least once every five years, NERC shall conduct an audit to evaluate how each Regional Entity Compliance Monitoring and Enforcement Program implements the NERC Compliance Monitoring and Enforcement Program. The evaluation shall be based on these Rules of Procedure, including Appendix 4C, the delegation agreement, directives in effect pursuant to the delegation agreement, approved annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plans, required Compliance Monitoring and Enforcement Program attributes, and the NERC Compliance Monitoring and Enforcement Program procedures. These evaluations shall be provided to the Applicable Governmental Authorities to demonstrate the effectiveness of each Regional Entity. In addition, audits of Cross-Border Regional Entities shall cover applicable requirements imposed on the Regional Entity by statute, regulation, or order of, or agreement with, provincial governmental and/or regulatory authorities for which NERC has auditing responsibilities over the Regional Entity's compliance with such requirements within Canada or Mexico. Participation of a representative of an Applicable Governmental Authority shall be subject to the limitations of sections 3.1.6 and 8.0 of Appendix 4C of these Rules of Procedure regarding disclosures of non-public compliance information related to other jurisdictions. NERC shall maintain an audit procedure containing the requirements, steps, and timelines to conduct an audit of each Regional Entity Compliance Monitoring and Enforcement Program. The current procedure is contained in the NERC Audit of Regional Entity Compliance Programs, which is incorporated into these rules as **Appendix 4A**.

1.3.1. NERC shall establish a program to audit bulk power system owners, operators, and users operating within a regional entity to verify the findings of previous compliance audits conducted by the regional entity to evaluate how well the regional entity compliance enforcement program is meeting its delegated authority and responsibility.

1.4 Applicable Governmental Authorities will be allowed to participate as an observer in any audit conducted by NERC of a Regional Entity's Compliance Monitoring and Enforcement Program. A representative of the Regional Entity being audited will be allowed to participate in the audit as an observer.

2. **Consistency Among Regional Compliance Monitoring and Enforcement Programs** — To provide for a consistent Compliance Monitoring and Enforcement Program for all Bulk Power System owners, operators, and users required to comply with approved Reliability Standards, NERC shall maintain a single, uniform Compliance Monitoring and Enforcement Program, which is incorporated into these rules of procedure as **Appendix 4C**. Any differences in Regional Entity Compliance Monitoring and Enforcement Program methods, including determination of violations and Penalty assessment, shall be justified on a case-by-case basis and fully documented in each Regional Entity delegation agreement.

2.1 NERC shall ensure that each of the Regional Entity Compliance Monitoring and Enforcement Programs meets these Rules of Procedure, including **Appendix 4C**, and follows the terms of the delegation agreement and the approved annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan.

2.2 NERC shall maintain a single, uniform Compliance Monitoring and Enforcement Program in **Appendix 4C** containing the procedures to ensure the consistency and fairness of the processes used to determine Regional Entity Compliance Monitoring and Enforcement Program findings of compliance and noncompliance, and the application of Penalties and sanctions.

2.3 NERC shall periodically conduct Regional Entity compliance manager forums. These forums shall use the results of Regional Entity Compliance Monitoring and Enforcement Program audits and findings of NERC Compliance Staff to identify and refine Regional Entity Compliance Monitoring and Enforcement Program differences into a set of best practices over time.

3. **Information Collection and Reporting** — NERC and the Regional Entities shall implement data management procedures that address data reporting requirements, data integrity, data retention, data security, and data confidentiality.

4. **Violation Disclosure** — NERC shall disclose all Confirmed Violations and maintain as confidential Possible Violations and Alleged Violations, according to the reporting and disclosure process in **Appendix 4C**.

5. **Authority to Determine Noncompliance, Levy Penalties and Sanctions, and Issue Remedial Action Directives** — NERC and Regional Entity Compliance Staff shall have the authority and responsibility to make initial determinations of compliance or noncompliance, and where authorized by the Applicable Governmental Authorities or where otherwise authorized, to determine Penalties and sanctions for noncompliance with a Reliability Standard, and issue Remedial Action Directives. Regional Entity boards or a compliance panel reporting directly to the Regional Entity board will be vested with the authority for the overall Regional Entity Compliance Monitoring and Enforcement Program and have the authority to impose Penalties and sanctions on behalf of NERC, where authorized by applicable legislation or agreement. Remedial Action Directives may be issued by NERC or a Regional Entity that is aware of a Bulk Power System owner, operator, or user that is, or is about to engage in an act or practice that would result, in noncompliance with a Reliability Standard, where such Remedial Action Directive is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat. If, after receiving such a Remedial Action Directive, the Bulk Power System owner, operator, or user does not take appropriate action to avert a violation of a Reliability Standard, NERC may petition the Applicable Governmental Authority to issue a compliance order.

6. **Due Process** — NERC shall establish and maintain a fair, independent, and nondiscriminatory appeals process. The appeals process is set forth in Sections 408-410. The process shall allow Bulk Power System owners, operators, and users to appeal the Regional Entity's findings of noncompliance and to appeal Penalties, sanctions, and Remedial Action Directives that are levied by the Regional Entity. Appeals beyond the NERC process will be heard by the Applicable Governmental Authority.

   The appeals process will also allow for appeals to NERC of any findings of noncompliance issued by NERC to a Regional Entity for Reliability Standards and Requirements where the Regional Entity is monitored for compliance to a Reliability Standard. No monetary Penalties will be levied in these matters; however sanctions, remedial actions, and directives to comply may be applied by NERC.

7. **Conflict Disclosure** — NERC shall disclose to the appropriate governmental authorities any potential conflicts between a market rule and the enforcement of a Regional Reliability Standard.

8. **Confidentiality** — To maintain the integrity of the NERC Compliance Monitoring and Enforcement Program, NERC and Regional Entity staff, Compliance Audit team members, and committee members shall maintain the

confidentiality of information obtained and shared during compliance monitoring and enforcement processes including Compliance Investigations, Compliance Audits, Spot Checks, drafting of reports, appeals, and closed meetings.

8.1 NERC and the Regional Entity shall have in place appropriate codes of conduct and confidentiality agreements for staff and other Compliance Monitoring and Enforcement Program participants.

8.2 Individuals not bound by NERC or Regional Entity codes of conduct who serve on compliance-related committees or Compliance Audit teams shall sign a NERC confidentiality agreement prior to participating on the committee or Compliance Audit team.

8.3 Information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information shall not be distributed outside of a committee or team, nor released publicly. Other information subject to confidentiality is identified in Section 1500.

8.4 In the event that a staff, committee, or Compliance Audit team member violates any of the confidentiality rules set forth above, the staff, committee, or Compliance Audit team member and any member organization with which the individual is associated may be subject to appropriate action by the Regional Entity or NERC, including prohibiting participation in future Compliance Monitoring and Enforcement Program activities.

9. **Auditor Training** — NERC shall develop and provide training in auditing skills to all people who participate in NERC and Regional Entity Compliance Audits. Training for NERC and Regional Entity personnel and others who serve as Compliance Audit team leaders shall be more comprehensive than training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

403. Required Attributes of Regional Entity Compliance Monitoring and Enforcement Programs

Each Regional Entity Compliance Monitoring and Enforcement Program shall promote excellence in the enforcement of Reliability Standards. To accomplish this goal, each Regional Entity Compliance Monitoring and Enforcement Program shall (i) conform to and comply with the NERC uniform Compliance Monitoring and Enforcement Program, **Appendix 4C** to these Rules of Procedure, except to the extent of any deviations that are stated in the Regional Entity's delegation agreement, and (ii) meet all of the attributes set forth in this Section 403.

Program Structure

1. **Independence** — Each Regional Entity's governance of its Compliance Monitoring and Enforcement Program shall exhibit independence, meaning the Compliance Monitoring and Enforcement Program shall be organized so that its compliance monitoring and enforcement activities are carried out separately from other activities of the Regional Entity. The Compliance Monitoring and Enforcement Program shall not be unduly influenced by the Bulk Power System owners, operators, and users being monitored or other Regional Entity activities that are required to meet the Reliability Standards. Regional Entities must include rules providing that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

2. **Exercising Authority** — Each Regional Entity Compliance Monitoring and Enforcement Program shall exercise the responsibility and authority in carrying out the delegated functions of the NERC Compliance Monitoring and Enforcement Program in accordance with delegation agreements and **Appendix 4C**. These functions include but are not limited to: data gathering, data reporting, Compliance Investigations, Compliance Audit activities, evaluating compliance and noncompliance, imposing Penalties and sanctions, and approving and tracking mitigation actions.

3. **Delegation of Authority** — To maintain independence, fairness, and consistency in the NERC Compliance Monitoring and Enforcement Program, a Regional Entity shall not sub-delegate its Compliance Monitoring and Enforcement Program duties to entities or persons other than the Regional Entity Compliance Staff, unless (i) required by statute or regulation in the applicable jurisdiction, or (ii) by agreement with express approval of NERC and of FERC or other Applicable Governmental Authority, to another Regional Entity.

4. **Hearings of Contested Findings or Sanctions —** The Regional Entity board or compliance panel reporting directly to the Regional Entity board will designate a Hearing Body (with appropriate recusal procedures) that will be vested with the authority for conducting all compliance hearings, pursuant to the hearing process selected under Section 403.15, in which any Bulk Power System owner, operator, or user provided a Notice of Alleged Violation may present facts and other information to contest a Notice of Alleged Violation or any proposed Penalty, sanction, any Remedial Action Directive, or any Mitigation Plan component. Compliance hearings shall be conducted in accordance with the Hearing Procedures set forth in Attachment 2 to **Appendix 4C**. If a stakeholder body serves as the Hearing Body, no two industry sectors may control any decision and no single sector may veto any matter related to compliance after recusals.

Program Resources

5. **Regional Entity Compliance Staff** — Each Regional Entity shall have sufficient resources to meet delegated compliance monitoring and enforcement responsibilities, including the necessary professional staff to manage and

implement the Regional Entity Compliance Monitoring and Enforcement Program.

6. **Regional Entity Compliance Staff Independence** — The Regional Entity Compliance Staff shall be capable of and required to make all determinations of compliance and noncompliance and determine Penalties, sanctions, and Remedial Action Directives and to review and accept Mitigation Plans and other Mitigating Activities.

   6.1 Regional Entity Compliance Staff shall not have a conflict of interest, real or perceived, in the outcome of compliance monitoring and enforcement processes, reports, or sanctions. The Regional Entity shall have in effect a conflict of interest policy.

   6.2 Regional Entity Compliance Staff shall have the authority and responsibility to carry out compliance monitoring and enforcement processes (with the input of industry subject matter experts), make determinations of compliance or noncompliance, and levy Penalties and sanctions without interference or undue influence from Regional Entity members and their representative or other industry entities.

   6.3 Regional Entity Compliance Staff may call upon independent technical subject matter experts who have no conflict of interest in the outcome of the compliance monitoring and enforcement process to provide technical advice or recommendations in the determination of compliance or noncompliance.

   6.4 Regional Entity Compliance Staff shall abide by the confidentiality requirements contained in Section 1500 and **Appendix 4C** of these Rules of Procedure, the NERC delegation agreement and other confidentiality agreements required by the NERC Compliance Monitoring and Enforcement Program.

   6.5 Contracting with independent consultants or others working for the Regional Entity Compliance Monitoring and Enforcement Program shall be permitted provided the individual has not received compensation from a Bulk Power System owner, operator, or user being monitored for a period of at least the preceding six months and owns no financial interest in any Bulk Power System owner, operator, or user being monitored for compliance to the Reliability Standard, regardless of where the Bulk Power System owner, operator, or user operates. Any such individuals for the purpose of these Rules of Procedure shall be considered as augmenting Regional Entity Compliance Staff.

7. **Use of Industry Subject Matter Experts and Regional Entity Members** — Industry experts and Regional Entity members may be called upon to provide

their technical expertise in Compliance Monitoring and Enforcement Program activities.

7.1 The Regional Entity shall have procedures defining the allowable involvement of industry subject matter experts and Regional Entity members. The procedures shall address applicable antitrust laws and conflicts of interest.

7.2 Industry subject matter experts and Regional Entity members shall have no conflict of interest or financial interests in the outcome of their activities.

7.3 Regional Entity members and industry subject matter experts, as part of teams or Regional Entity committees, may provide input to the Regional Entity Compliance Staff so long as the authority and responsibility for (i) evaluating and determining compliance or noncompliance and (ii) levying Penalties, sanctions, or Remedial Action Directives shall not be delegated to any person or entity other than the Compliance Staff of the Regional Entity. Industry subject matter experts, Regional Entity members, or Regional Entity committees shall not make determinations of noncompliance or levy Penalties, sanctions, or Remedial Action Directives. Any committee involved shall be organized so that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

7.4 Industry subject matter experts and Regional Entity members shall sign a confidentiality agreement appropriate for the activity being performed.

7.5 All industry subject matter experts and Regional Entity members participating in Compliance Audits and Compliance Investigations shall successfully complete auditor training provided by NERC or the Regional Entity prior to performing these activities

Program Design

8. **Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan Content** — All approved Reliability Standards shall be included in the Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan for all Bulk Power System owners, operators, and users within the defined boundaries of the Regional Entity. Compliance to approved Regional Reliability Standards is applicable only within the Region of the Regional Entity that submitted those particular Regional Reliability Standards for approval. NERC will identify the risk elements and related Reliability Standards and Requirements to be considered by the Regional Entity in a given year in developing oversight plans for individual Registered Entities.

9. **Antitrust Provisions** — Each Regional Entity's Compliance Monitoring and Enforcement Program shall be structured and administered to abide by U.S. antitrust law and Canadian competition law.

10. **Information Submittal** — All Bulk Power System owners, operators, and users within the Regional Entity responsible for complying with Reliability Standards shall submit timely and accurate information when requested by the Regional Entity or NERC. NERC and the Regional Entities shall preserve any mark of confidentiality on information submitted pursuant to Section 1502.1.

    10.1 Each Regional Entity has the authority to collect the necessary information to determine compliance and shall develop processes for gathering data from the Bulk Power System owners, operators, and users the Regional Entity monitors.

    10.2 The Regional Entity or NERC has the authority to request information from Bulk Power System owners, operators, and users pursuant to Section 401.3 or this Section 403.10 without invoking a specific compliance monitoring and enforcement process in **Appendix 4C**, for purposes of determining whether to pursue one such process in a particular case and/or validating in the enforcement phase of a matter the conclusions reached through the compliance monitoring and enforcement process(es).

    10.3 When required or requested, the Regional Entities shall report information to NERC promptly and in accordance with **Appendix 4C** and other NERC procedures.

    10.4 Regional Entities shall notify NERC of all Possible, Alleged and Confirmed Violations of NERC Reliability Standards by Registered Entities over which the Regional Entity has compliance monitoring and enforcement authority, in accordance with **Appendix 4C**.

    10.5 A Bulk Power System owner, operator, or user found in noncompliance with a Reliability Standard shall submit a Mitigation Plan with a timeline addressing how the noncompliance will be corrected, unless an enforcement process is used that does not require a Mitigation Plan. The Regional Entity Compliance Staff shall review and accept the Mitigation Plan in accordance with **Appendix 4C**.

    10.6 An officer of a Bulk Power System owner, operator, or user shall certify as accurate all compliance data Self-Reported to the Regional Entity Compliance Monitoring and Enforcement Program.

    10.7 Regional Entities shall develop and implement procedures to verify the compliance information submitted by Bulk Power System owners, operators, and users.

11. **Compliance Audits of Bulk Power System Owners, Operators, and Users** — Each Regional Entity will maintain and implement a program of proactive Compliance Audits of Bulk Power System owners, operators, and users responsible for complying with Reliability Standards, in accordance with **Appendix 4C**. A Compliance Audit is a process in which a detailed review of the activities of a Bulk Power System owner, operator, or user is performed to determine if that Bulk Power System owner, operator, or user is complying with approved Reliability Standards.

    11.1 For an entity registered as a Balancing Authority, Reliability Coordinator, or Transmission Operator, the Compliance Audit will be performed at least once every three years. For other Bulk Power System owners, operators, and users on the NERC Compliance Registry, Compliance Audits shall be performed on a schedule established by NERC.

    11.2 Compliance Audits of Balancing Authorities, Reliability Coordinators, and Transmission Operators will include a component at the audited entity's site. For other Bulk Power System owners, operators, and users on the NERC Compliance Registry, the Compliance Audit may be either an on-site Compliance Audit or based on review of documents, as determined to be necessary and appropriate by NERC or Regional Entity Compliance Staff.

    11.3 Compliance Audits must include a detailed review of the activities of the Bulk Power System owner, operator, or user to determine if the Bulk Power System owner, operator, or user is complying with all approved Reliability Standards identified for audit by NERC. The Compliance Audit shall include a review of supporting documentation and evidence used by the Bulk Power System owner, operator or user to demonstrate compliance for an appropriate period prior to the Compliance Audit.

12. **Confidentiality of Compliance Monitoring and Enforcement Processes** — All compliance monitoring and enforcement processes, and information obtained from such processes, are to be non-public and treated as confidential in accordance with Section 1500 and **Appendix 4C** of these Rules of Procedure, unless NERC, the Regional Entity or FERC or another Applicable Governmental Authority with jurisdiction determines a need to conduct a Compliance Monitoring and Enforcement Program process on a public basis, provided, that NERC and the Regional Entities shall publish (i) schedules of Compliance Audits scheduled in each year, (ii) a public report of each Compliance Audit, and (iii) Notices of Penalty and settlement agreements. Advance authorization from the Applicable Governmental Authority is required to make public any compliance monitoring and enforcement process or any information relating to a compliance monitoring and enforcement process, or to permit interventions when determining whether to impose a Penalty. This prohibition on making public any compliance monitoring and enforcement process does not prohibit NERC or a Regional Entity from publicly disclosing (i) the initiation of or results from an analysis of a

significant system event under Section 807 or of off-normal events or system performance under Section 808, or (ii) information of general applicability and usefulness to owners, operators, and users of the Bulk Power System concerning reliability and compliance matters, so long as specific allegations or conclusions regarding Possible or Alleged Violations of Reliability Standards are not included in such disclosures.

13. **Critical Energy Infrastructure Information** — Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident will be identified and protected from public disclosure as Critical Energy Infrastructure Information. In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information shall be redacted according to NERC procedures and shall not be released publicly.

14. **Penalties, Sanctions, and Remedial Action Directives** — Each Regional Entity will apply all Penalties, sanctions, and Remedial Action Directives in accordance with the approved *Sanction Guidelines*, **Appendix 4B** to these Rules of Procedure. Any changes to the *Sanction Guidelines* to be used by any Regional Entity must be approved by NERC and submitted to the Applicable Governmental Authority for approval. All Confirmed Violations, Penalties, and sanctions, including Confirmed Violations, Penalties and sanctions specified in a Regional Entity Hearing Body decision, will be provided to NERC for review and filing with Applicable Governmental Authorities as a Notice of Penalty, in accordance with **Appendix 4C**.

15. **Hearing Process** — Each Regional Entity shall adopt either the Regional Entity Hearing Process (Section 403.15A) or the Consolidated Hearing Process (403.15B) and conduct all hearings pursuant to the selected process. In either case, the selected hearing process shall be a fair, independent, and nondiscriminatory process for hearing contested violations and any Penalties or sanctions levied, in conformance with Attachment 2 to **Appendix 4C** to these Rules of Procedure and any deviations therefrom that are set forth in the Regional Entity's delegation agreement. The hearing process shall allow Bulk Power System owners, operators, and users to contest findings of compliance violations, any Penalties and sanctions that are proposed to be levied, proposed Remedial Action Directives, and components of proposed Mitigation Plans. The hearing process shall (i) include provisions for recusal of any members of the Hearing Body with a potential conflict of interest, real or perceived, from all compliance matters considered by the Hearing Body for which the potential conflict of interest exists and (ii) provide that no two industry sectors may control any decision and no single sector may veto any matter brought before the Hearing Body after recusals.

    A Regional Entity may modify its selection of hearing process by giving notice to NERC six (6) months prior to such modification becoming effective. Hearings

will be conducted pursuant to the process in effect at the Regional Entity at the time of the submission of the hearing request by the registered entity.

Each Regional Entity will notify NERC of all hearings and NERC may observe any of the proceedings. Each Regional Entity will notify NERC of the outcome of all hearings.

If a Bulk Power System owner, operator, or user or a Regional Entity has completed the Regional Entity Hearing Process or the Consolidated Hearing Process and desires to appeal the outcome of the hearing, the Bulk Power System owner, operator, or user or the Regional Entity shall appeal to NERC in accordance with Section 409 of these Rules of Procedure, except that a determination of violation or Penalty that has been directly adjudicated by an Applicable Governmental Authority shall be appealed with that Applicable Governmental Authority.

15A. **Regional Entity Hearing Process** — The Regional Entity Hearing Process shall be conducted before a Hearing Body composed of the Regional Entity board or a balanced committee established by and reporting to the Regional Entity board as the final adjudicator at the Regional Entity level, provided, that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions.

15B. **Consolidated Hearing Process** — The Consolidated Hearing Process shall be conducted before a Hearing Body composed of five members, unless a smaller number is necessary, as discussed below. The Hearing Body will issue a final decision, provided that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions. Up to two members will be appointed by the Regional Entity from which the case originates. If stakeholder members are appointed, the stakeholders shall not represent the same industry sector. Should a Regional Entity choose to appoint one or no representative, then the NERC Board of Trustees Compliance Committee will select additional representatives to fill those vacancies. The Compliance Committee will appoint the NERC representatives to the Hearing Body, chosen among NERC trustees not serving on the Compliance Committee at the time of the request for hearing. The Regional Entity and NERC members appointed to the Hearing Body will appoint an additional member to the Hearing Body, chosen among NERC trustees not serving on the Compliance Committee at the time of the request for hearing or from the Regional Entity which the case originates. If the Hearing Body does not select a NERC trustee or a regional representative, the Hearing Body will appoint an additional member in accordance with the criteria specified in Appendix 4C, Attachment 2, Section 1.4.3(a). In the event a Regional Entity chooses not to appoint representatives to the Hearing Body and there are not five NERC trustees available to participate on the Hearing Body, as determined by the Compliance Committee, the Hearing Body may be composed of three members (three NERC trustees not serving on the Compliance Committee). The Hearing Body will appoint a Hearing Officer to preside over the hearing.

16. **Annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan** — Each Regional Entity shall annually develop and submit to NERC for approval a Regional Entity Compliance Monitoring and Enforcement Implementation Plan in accordance with **Appendix 4C** that, includes details on regional risk assessment processes and results, Reliability Standards and Requirements associated with regional risk assessment results, the methods to be used by the Regional Entity for reporting, monitoring, evaluating, and assessing performance criteria and the Regional Entity's Annual Audit Plan. These Regional Implementation Plans will be submitted to NERC on the schedule established by NERC, generally on or about October 1 of the preceding year. In conjunction with the annual Regional Implementation Plan, each Regional Entity must report to NERC regarding how it carried out its delegated compliance monitoring and enforcement authority in the previous year, the effectiveness of the Compliance Monitoring and Enforcement Program, and changes expected to correct any deficiencies identified. Each Regional Entity will provide its annual report on the schedule established by NERC, generally on or about February 15 of the following year.

404. NERC Monitoring of Compliance for Regional Entities or Bulk Power Owners, Operator, or Users

NERC shall monitor Regional Entity compliance with NERC Reliability Standards and, if no there is no delegation agreement in effect with a Regional Entity for the geographic area, shall monitor Bulk Power System owners, operators, and users for compliance with NERC Reliability Standards. Industry subject matter experts may be used as appropriate in Compliance Investigations, Compliance Audits, and other Compliance Monitoring and Enforcement Program activities, subject to confidentiality, antitrust, and conflict of interest provisions.

1. **NERC Obligations** — NERC Compliance Staff shall monitor the compliance of the Regional Entity with the Reliability Standards for which the Regional Entities are responsible, in accordance with **Appendix 4C**. NERC shall actively monitor in its annual Compliance Enforcement and Monitoring Program selected Reliability Standards that apply to the Regional Entities. NERC shall evaluate compliance and noncompliance with all of the Reliability Standards that apply to the Regional Entities and shall impose sanctions, Penalties, or Remedial Action Directives when there is a finding of noncompliance. NERC shall post all violations of Reliability Standards that apply to the Regional Entities as described in the reporting and disclosure process in **Appendix 4C**.

   In addition, NERC will directly monitor Bulk Power System owners, operators, and users for compliance with NERC Reliability Standards in any geographic area for which there is not a delegation agreement in effect with a Regional Entity, in accordance with **Appendix 4C**. In such cases, NERC will serve as the Compliance Enforcement Authority described in **Appendix 4C**. Compliance matters contested by Bulk Power System owners, operators, and users in such an event will be heard by the NERC Compliance and Certification Committee.

2. **Compliance Audit of the Regional Entity** — NERC shall perform a Compliance Audit of each Regional Entity responsible for complying with Reliability Standards at least once every three years. NERC shall make an evaluation of compliance based on the information obtained through the Compliance Audit. After due process is complete, the final Compliance Audit report shall be made public in accordance with the reporting and disclosure process in **Appendix 4C**.

3. **Appeals Process** — Any Regional Entity or Bulk Power System owner, operator or user found by NERC, as opposed to a Regional Entity, to be in noncompliance with a Reliability Standard may appeal the findings of noncompliance with Reliability Standards and any sanctions or Remedial Action Directives that are issued by, or Mitigation Plan components imposed by, NERC, pursuant to the processes described in Sections 408 through 410.

405. Monitoring of Reliability Standards and Other Requirements Applicable to NERC

The NERC Compliance and Certification Committee shall establish and implement a process to monitor NERC's compliance with the Reliability Standards that apply to NERC. The process shall use independent monitors with no conflict of interest, real or perceived, in the outcomes of the process. All violations shall be made public according to the reporting and disclosure process in **Appendix 4C**. The Compliance and

Certification Committee will also establish a procedure for monitoring NERC's compliance with its Rules of Procedure for the Standards Development, Compliance Monitoring and Enforcement, and Organization Registration and Certification Programs. Such procedures shall not be used to circumvent the appeals processes established for those programs.

406. Independent Audits of the NERC Compliance Monitoring and Enforcement Program

NERC shall provide for an independent audit of its Compliance Monitoring and Enforcement Program at least once every three years, or more frequently as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board. The independent audit shall meet the following minimum requirements and any other requirements established by the NERC Board.

1. **Effectiveness** — The audit shall evaluate the success and effectiveness of the NERC Compliance Monitoring and Enforcement Program in achieving its mission.

2. **Relationship** — The audit shall evaluate the relationship between NERC and the Regional Entity Compliance Monitoring and Enforcement Programs and the effectiveness of the programs in ensuring reliability.

3. **Final Report Posting** — The final report shall be posted by NERC for public viewing in accordance with **Appendix 4C**.

4. **Response to Recommendations** — If the audit report includes recommendations to improve the NERC Compliance Monitoring and Enforcement Program, the administrators of the NERC Compliance Monitoring and Enforcement Program shall provide a written response and plan to the Board within 30 days of the release of the final audit report.

407. Penalties, Sanctions, and Remedial Action Directives

1. **NERC Review of Regional Entity Penalties and Sanctions —** NERC shall review all Penalties, sanctions, and Remedial Action Directives imposed by each Regional Entity for violations of Reliability Standards, including Penalties, sanctions and Remedial Action Directives that are specified by a Hearing Body final decision issued pursuant to Attachment 2 to **Appendix 4C**, to determine if the Regional Entity's determination is supported by a sufficient record compiled by the Regional Entity, is consistent with the *Sanction Guidelines* incorporated into these Rules of Procedure as **Appendix 4B** and with other directives, guidance and directions issued by NERC pursuant to the delegation agreement, and is consistent with Penalties, sanctions and Remedial Action Directives imposed by the Regional Entity and by other Regional Entities for violations involving the same or similar facts and circumstances.

2. **Developing Penalties and Sanctions** — The Regional Entity Compliance Staff shall use the *Sanction Guidelines*, which are incorporated into these Rules of

Procedure as **Appendix 4B**, to develop an appropriate Penalty, sanction, or Remedial Action Directive for a violation, and shall notify NERC of the Penalty, sanction or Remedial Action Directive.

3. **Effective Date of Penalty** — Where authorized by applicable legislation or agreement, no Penalty imposed for a violation of a Reliability Standard shall take effect until the thirty-first day after NERC files, with the Applicable Governmental Authority, a "Notice of Penalty" and the record of the proceedings in which the violation and Penalty were determined, or such other date as ordered by the Applicable Governmental Authority.

408. Review of NERC Decisions

1. **Scope of Review** — A Registered Entity or a Regional Entity wishing to challenge a finding of noncompliance and the imposition of a Penalty for a compliance measure directly administered by NERC, or a Regional Entity wishing to challenge a Regional Entity Compliance Monitoring and Enforcement Program audit finding, may do so by filing a notice of the challenge with NERC's Director of Enforcement no later than 21 days after issuance of the notice of finding of violation or audit finding. Appeals by Registered Entities or Regional Entities of decisions of Hearing Bodies shall be pursuant to Section 409.

2. **Contents of Notice** — The notice of challenge shall include the full text of the decision that is being challenged, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief.

3. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of challenge, the NERC Director of Enforcement may file with the Hearing Panel a response to the issues raised in the notice, with a copy to the Regional Entity.

4. **Hearing by Compliance and Certification Committee** — The NERC Compliance and Certification Committee shall provide representatives of the Regional Entity or Registered Entity, and the NERC Compliance Monitoring and Enforcement Program an opportunity to be heard and shall decide the matter based upon the filings and presentations made, with a written explanation of its decision.

5. **Appeal** — The Regional Entity or Registered Entity may appeal the decision of the Compliance and Certification Committee by filing a notice of appeal with NERC's Director of Enforcement no later than 21 days after issuance of the written decision by the Compliance and Certification Committee. The notice of appeal shall include the full text of the written decision of the Compliance and Certification Committee that is being appealed, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be

presented in the appeal that was not presented to the Compliance and Certification Committee.

6. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of appeal, the NERC Compliance Monitoring and Enforcement Program staff may file its response to the issues raised in the notice of appeal, with a copy to the entity filing the notice.

7. **Reply** — The entity filing the appeal may file a reply within 7 days.

8. **Decision** — The Compliance Committee of the NERC Board of Trustees shall decide the appeal, in writing, based upon the notice of appeal, the record, the response, and any reply. At its discretion, the Compliance Committee may invite representatives of the Regional Entity or Registered Entity, and the NERC Compliance Monitoring and Enforcement Program to appear before the Compliance Committee. Decisions of the Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

9. **Impartiality** — No member of the Compliance and Certification Committee or the Board of Trustees Compliance Committee having an actual or perceived conflict of interest in the matter may participate in any aspect of the challenge or appeal except as a party or witness.

10. **Expenses** — Each party in the challenge and appeals processes shall pay its own expenses for each step in the process.

11. **Non-Public Proceedings —** All challenges and appeals shall be closed to the public to protect Confidential Information.

409. Appeals from Final Decisions of Hearing Bodies

1. **Time for Appeal** — A Regional Entity acting as the Compliance Enforcement Authority, or an owner, operator or user of the Bulk Power System, shall be entitled to appeal from a final decision of a Hearing Body concerning an Alleged Violation of a Reliability Standard, a proposed Penalty or sanction for violation of a Reliability Standard, a proposed Mitigation Plan, or a proposed Remedial Action Directive, by filing a notice of appeal with NERC's Director of Enforcement, with copies to the Clerk, the Regional Entity, and any other Participants in the Hearing Body proceeding, no later than 21 days after issuance of the final decision of the Hearing Body. The Compliance Committee shall render its decision within 180 days following the receipt by NERC's Director of Enforcement of the notice of appeal. The Compliance Committee may extend this deadline for good cause and shall provide written notice of any extension to all Participants.

2. **Contents** — The notice of appeal shall include the full text of the final decision of the Hearing Body that is being appealed, a concise statement of the error or errors contained in the final decision, a clear statement of the relief being sought,

and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not first presented during the proceeding before the Hearing Body.

3. **Response to Notice of Appeal** — Within 21 days after the date the notice of appeal is filed, the Clerk shall file the entire record of the Hearing Body proceeding with NERC's Director of Enforcement, with a copy to all Participants. Within 35 days after the date of the notice of appeal, all Participants in the proceeding before the Hearing Body, other than the Participant filing the notice of appeal, shall file their responses to the issues raised in the notice of appeal.

4. **Reply** — The party filing the appeal may file a reply to the responses within 7 days.

5. **Decision** — The Compliance Committee of the NERC Board of Trustees shall decide the appeal, in writing, based upon the notice of appeal, the record of the proceeding before the Hearing Body, the responses, and any reply filed with NERC. The Compliance Committee shall review the appealed issue(s) under a *de novo* standard. At its discretion, the Compliance Committee may invite representatives of the entity making the appeal and the other Participants in the proceeding before the Hearing Body to appear before the Committee. Decisions of the Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

6. **Expenses** — Each party in the appeals process shall pay its own expenses for each step in the process.

7. **Non-Public Proceedings** — All appeals shall be closed to the public to protect Confidential Information.

8. **Appeal of Hearing Body Decisions Granting or Denying Motions to Intervene** — This section is not applicable to an appeal of a decision of a Hearing Body granting or denying a motion to intervene in the Hearing Body proceeding. Appeals of decisions of Hearing Bodies granting or denying motions to intervene in Hearing Body proceedings shall be processed and decided pursuant to Section 414.

410. Hold Harmless

A condition of invoking the challenge or appeals processes under Section 408 or 409 is that the entity requesting the challenge or appeal agrees that neither NERC (defined to include its Members, Board of Trustees, committees, subcommittees, staff and industry subject matter experts), any person assisting in the challenge or appeals processes, nor any company employing a person assisting in the challenge or appeals processes, shall be liable, and they shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the challenge or appeals proceeding. This "hold harmless"

clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

411. Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards

A Registered Entity that is subject to an Applicable Requirement of a NERC Critical Infrastructure Protection Standard for which Technical Feasibility Exceptions are permitted, may request a Technical Feasibility Exception to the Requirement, and the request will be reviewed, approved or disapproved, and if approved, implemented, in accordance with the NERC *Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standard*, Appendix 4D to these Rules of Procedure.

412. Certification of Questions from Hearing Bodies for Decision by the NERC Board of Trustees Compliance Committee

1. A Hearing Body that is conducting a hearing concerning a disputed compliance matter pursuant to Attachment 2, Hearing Procedures, of Appendix 4C, may certify to the Board of Trustees Compliance Committee, for decision, a significant question of law, policy or procedure the resolution of which may be determinative of the issues in the hearing in whole or in part, and as to which there are other extraordinary circumstances that make prompt consideration of the question by the Compliance Committee appropriate, in accordance with Section 1.5.12 of the Hearing Procedures. All questions certified by a Hearing Body to the Board of Trustees Compliance Committee shall be considered and disposed of by the Compliance Committee.

2. The Compliance Committee may accept or reject a certification of a question for decision. If the Compliance Committee rejects the certified question, it shall issue a written statement that the certification is rejected.

3. If the Compliance Committee accepts the certification of a question for decision, it shall establish a schedule by which the Participants in the hearing before the Hearing Body may file memoranda and reply memoranda stating their positions as to how the question certified for decision should be decided by the Compliance Committee. The Compliance Committee may also request, or provide an opportunity for, the NERC compliance operations department, the NERC compliance enforcement department, and/or the NERC general counsel to file memoranda stating their positions as to how the question certified for decision should be decided. After receiving such memoranda and reply memoranda as are filed in accordance with the schedule, the Compliance Committee shall issue a written decision on the certified question.

4. Upon receiving the Compliance Committee's written decision on the certified question, the Hearing Body shall proceed to complete the hearing in accordance with the Compliance Committee's decision.

5. The Compliance Committee's decision, if any, on the certified question shall only be applicable to the hearing from which the question was certified and to the Participants in that hearing.

413. Review and Processing of Hearing Body Final Decisions that Are Not Appealed

NERC shall review and process all final decisions of Hearing Bodies issued pursuant to Attachment 2 to Appendix 4C concerning an Alleged Violation, proposed Penalty or sanction, or proposed Mitigation Plan that are not appealed pursuant to Section 409, as though the determination had been made by the Regional Entity Compliance Monitoring and Enforcement Program. NERC shall review and process such final decisions, and may require that they be modified by the Regional Entity, in accordance with, as applicable to the particular decision, Sections 5.8, 5.9 and 6.5 of Appendix 4C.

414. Appeals of Decisions of Hearing Bodies Granting or Denying Motions to Intervene in Hearing Body Proceedings

1. **Time to Appeal** — An entity may appeal a decision of a Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** denying the entity's motion to intervene in a Hearing Body proceeding, and the Regional Entity Compliance Staff or any other Participant in the Hearing Body proceeding may appeal a decision of the Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** granting or denying a motion to intervene in the Hearing Body proceeding, in either case by filing a notice of appeal with the NERC Director of Enforcement, with copies to the Clerk of the Hearing Body, the Hearing Body, the Hearing Officer, the Regional Entity Compliance Staff, and all other Participants in the Hearing Body proceeding, no later than seven (7) days following the date of the Hearing Body decision granting or denying the motion to intervene.

2. **Contents of Notice of Appeal** — The notice of appeal shall set forth information and argument to demonstrate that the decision of the Hearing Body granting or denying the motion to intervene was erroneous under the grounds for intervention specified in Section 1.4.4 of Attachment 2 of **Appendix 4C** and that the entity requesting intervention should be granted or denied intervention, as applicable. Facts alleged in, and any offers of proof made in, the notice of appeal shall be supported by affidavit or verification. The notice of appeal shall include a copy of the original motion to intervene and a copy of the decision of the Hearing Body granting or denying the motion to intervene.

3. **Responses to Notice of Appeal** — Within ten (10) days following the date the notice of appeal is filed, the Clerk shall transmit to the NERC Director of Enforcement copies of all pleadings filed in the Hearing Body proceeding on the motion to intervene. Within fourteen (14) days following the date the notice of appeal is filed, the Hearing Body, the Regional Entity Compliance Staff, and any other Participants in the Hearing Body proceeding, may each file a response to the notice of appeal with the NERC Director of Enforcement. Within seven (7) days following the last day for filing responses, the entity filing the notice of appeal,

and any Participant in the Hearing Body proceeding that supports the appeal, may file replies to the responses with the NERC Director of Enforcement.

4. **Disposition of Appeal** — The appeal shall be considered and decided by the Compliance Committee. The NERC Director of Enforcement shall provide copies of the notice of appeal and any responses and replies to the Compliance Committee. The Compliance Committee shall issue a written decision on the appeal; provided, that if the Compliance Committee does not issue a written decision on the appeal within forty-five (45) days following the date of filing the notice of appeal, the appeal shall be deemed denied and the decision of the Hearing Body granting or denying the motion to intervene shall stand. The NERC Director of Enforcement shall transmit copies of the Compliance Committee's decision, or shall provide notice that the forty-five (45) day period has expired with no decision by the Compliance Committee, to the Clerk, the Hearing Body, the entity filing the notice of appeal, the Regional Entity Compliance Staff, and any other Participants in the Hearing Body proceeding that filed responses to the notice of appeal or replies to responses.

5. **Appeal of Compliance Committee Decision to FERC or Other Applicable Governmental Authority** — Any entity aggrieved by the decision of the Compliance Committee on an appeal of a Hearing Body decision granting or denying a motion to intervene in a Hearing Body proceeding (including a denial of such appeal by the expiration of the forty-five (45) day period as provided in Section 414.4) may appeal or petition for review of the decision of the Compliance Committee to FERC or to another Applicable Governmental Authority having jurisdiction over the matter, in accordance with the authorities, rules and procedures of FERC or such other Applicable Governmental Authority. Any such appeal or petition for review shall be filed within the time period, if any, and in the form and manner, specified by the applicable statutes, rules or regulations governing proceedings before FERC or the other Applicable Governmental Authority.

SECTION 500 — ORGANIZATION REGISTRATION AND CERTIFICATION

501. Scope of the Organization Registration and Organization Certification Programs

The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards. Registered Entities are not and do not become Members of NERC or a Regional Entity, by virtue of being listed on the NCR. Membership in NERC is governed by Article II of NERC's Bylaws; membership in a Regional Entity or regional reliability organization is governed by that entity's bylaws or rules.

The purpose of the Organization Certification Program is to ensure that the new entity (i.e., applicant to be an RC, BA, or TOP that is not already performing the function for which it is applying to be certified as) has the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) for which it is applying thereby demonstrating the ability to become certified and then operational.

Organization Registration and Organization Certification may be delegated to Regional Entities in accordance with the procedures in this Section 500; the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into these Rules of Procedure as **Appendix 5A**; and, approved Regional Entity delegation agreements or other applicable agreements.

1. **NERC Compliance Registry** — NERC shall establish and maintain the NCR of the Bulk Power System owners, operators, and users that are subject to approved Reliability Standards.

   1.1 (a) The NCR shall set forth the identity and functions performed for each organization responsible for meeting Requirements/sub-Requirements of the Reliability Standards. Bulk Power System owners, operators, and users (i) shall provide to NERC and the applicable Regional Entity information necessary to complete the Registration, and (ii) shall provide NERC and the applicable Regional Entity with timely updates to information concerning the Registered Entity's ownership, operations, contact information, and other information that may affect the Registered Entity's Registration status or other information recorded in the Compliance Registry.

   (b) A generation or transmission cooperative, a joint-action agency or another organization may register as a Joint Registration Organization (JRO), in lieu of each of the JRO's members or related entities being registered individually for one or more functions. Refer to Section 507.

(c) Multiple entities may each register using a Coordinated Functional Registration (CFR) for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function pursuant to a written agreement for the division of compliance responsibility. Refer to Section 508.

1.2 In the development of the NCR, NERC and the Regional Entities shall determine which organizations should be placed on the NCR based on the criteria provided in the NERC *Statement of Compliance Registry Criteria* which is incorporated into these Rules of Procedure as **Appendix 5B**.

1.3 NERC and the Regional Entities shall use the following rules for establishing and maintaining the NCR based on the Registration criteria as set forth in **Appendix 5B** *Statement of Compliance Registry Criteria*:

1.3.1 NERC shall notify each organization that it is on the NCR. The Registered Entity is responsible for compliance with all the Reliability Standards applicable to the functions for which it is registered from the time it receives the Registration notification from NERC.

1.3.2 Any organization receiving such a notice may challenge its placement on the NCR according to the process in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section V.

1.3.3 The Compliance Committee of the Board of Trustees shall promptly issue a written decision on the challenge, including the reasons for the decision.

1.3.4 The decision of the Compliance Committee of the Board of Trustees shall be final unless, within 21 days of the date of the Compliance Committee of the Board of Trustees decision, the organization appeals the decision to the Applicable Governmental Authority.

1.3.5 Each Registered Entity identified on the NCR shall notify its corresponding Regional Entity(s) of any corrections, revisions, deletions, changes in ownership, corporate structure, or similar matters that affect the Registered Entity's responsibilities with respect to the Reliability Standards. Failure to notify will not relieve the Registered Entity from any responsibility to comply with the Reliability Standards or shield it from any Penalties or sanctions associated with failing to comply with the Reliability Standards applicable to its associated Registration.

1.4 For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall:

1.4.1 Ensure that all areas are under the oversight of one and only one Reliability Coordinator.

1.4.2 Ensure that all Balancing Authorities and Transmission Operator entities[2] are under the responsibility of one and only one Reliability Coordinator.

1.4.3 Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator.

1.4.4 Ensure that all Loads and generators are under the responsibility and control of one and only one Balancing Authority.

1.5 NERC shall maintain the NCR of organizations responsible for meeting the Requirements/sub-Requirements of the Reliability Standards currently in effect on its website and shall update the NCR monthly.

1.6 With respect to: (i) entities to be registered for the first time; (ii) currently-registered entities or (iii) previously-registered entities, for which registration status changes are sought, including availability and composition of a sub-set list of applicable Reliability Standards (which specifies the Reliability Standards and may specify Requirements/sub-Requirements), the registration process steps in Section III of **Appendix 5A** apply.

1.7 NERC shall establish a NERC-led, centralized review panel, comprised of a NERC lead with Regional Entity participants, in accordance with **Appendix 5A**, *Organization Registration and Organization Certification Manual*, Section III.D and **Appendix 5B**, *Statement of Compliance Registry Criteria*.

2. **Entity Certification** — NERC shall provide for Certification of all entities with primary reliability responsibilities requiring Certification. This includes those

[2] Some organizations perform the listed functions (e.g., Balancing Authority, Transmission Operator) over areas that transcend the Footprints of more than one Reliability Coordinator. Such organizations will have multiple Registrations, with each such Registration corresponding to that portion of the organization's overall area that is within the Footprint of a particular Reliability Coordinator.

entities that satisfy the criteria established in the NERC provisional Certification process. The NERC programs shall:

2.1 Evaluate and certify the competency of entities performing reliability functions. The entities presently expected to be certified include Reliability Coordinators, Transmission Operators, and Balancing Authorities.

2.2 Evaluate and certify each applicant's ability to meet the requirements for Certification.

2.3 Maintain process documentation.

2.4 Maintain records of currently certified entities.

2.5 Issue a Certification document to the applicant that successfully demonstrates its competency to perform the evaluated functions.

3. **Delegation and Oversight**

3.1 NERC may delegate responsibilities for Organization Registration and Organization Certification to Regional Entities in accordance with requirements established by NERC. Delegation will be via the delegation agreement between NERC and the Regional Entity or other applicable agreement. The Regional Entity shall administer Organization Registration and Organization Certification Programs in accordance with such delegations to meet NERC's programs goals and requirements subject to NERC oversight.

3.2 NERC shall develop and maintain a plan to ensure the continuity of Organization Registration and Organization Certification within the geographic or electrical boundaries of a Regional Entity in the event that no entity is functioning as a Regional Entity for that Region, or the Regional Entity withdraws as a Regional Entity, or does not operate its Organization Registration and Organization Certification Programs in accordance with delegation agreements.

3.3 NERC shall develop and maintain a program to monitor and oversee the NERC Organization Registration and Organization Certification Programs activities that are delegated to each Regional Entity through a delegation agreement or other applicable agreement.

3.3.1 This program shall monitor whether the Regional Entity carries out those delegated activities in accordance with NERC requirements, and whether there is consistency, fairness of administration, and comparability.

3.3.2 Monitoring and oversight shall be accomplished through direct participation in the Organization Registration and Organization Certification Programs with periodic reviews of documents and records of both programs.

502. Organization Registration and Organization Certification Program Requirements

1. NERC shall maintain the Organization Registration and Organization Certification Programs.

   1.1 The roles and authority of Regional Entities in the programs are delegated from NERC pursuant to the Rules of Procedure through regional delegation agreements or other applicable agreements.

   1.2 Processes for the programs shall be administered by NERC and the Regional Entities. Materials that each Regional Entity uses are subject to review and approval by NERC.

   1.3 The appeals process for the Organization Registration and Organization Certification Programs are identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Sections V and VI, respectively.

   1.4 The Certification Team membership is identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section IV.8.d.

2. To ensure consistency and fairness of the Organization Registration and Organization Certification Programs, NERC shall develop procedures to be used by all Regional Entities and NERC in accordance with the following criteria:

   2.1 NERC and the Regional Entities shall have data management processes and procedures that provide for confidentiality, integrity, and retention of data and information collected.

   2.2 Documentation used to substantiate the conclusions of the Regional Entity/ NERC related to Registration and/or Certification must be retained by the Regional Entity for (6) six years, unless a different retention period is otherwise identified, for the purposes of future audits of these programs.

   2.3 To maintain the integrity of the NERC Organization Registration and Organization Certification Programs, NERC, Regional Entities, Certification Team members, program audit team members (Section 506), and committee members shall maintain the confidentiality of information provided by an applicant or entities.

      2.2.1 NERC and the Regional Entities shall have appropriate codes of conduct and confidentiality agreements for staff, Certification

Team, Certification related committees, and Certification program audit team members.

2.2.2 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall maintain the confidentiality of any Registration or Certification-related discussions or documents designated as confidential (see Section 1500 for types of Confidential Information).

2.2.3 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall treat as confidential the individual comments expressed during evaluations, program audits and report-drafting sessions.

2.2.4 Copies of notes, draft reports, and other interim documents developed or used during an entity Certification evaluation or program audit shall be destroyed after the public posting of a final, uncontested report.

2.2.5 Information deemed by an applicant, entity, a Regional Entity, or NERC as confidential, including Critical Energy Infrastructure Information, shall not be released publicly or distributed outside of a committee or team.

2.2.6 In the event that an individual violates any of the confidentiality rules set forth above, that individual and any member organization with which the individual is associated will be subject to immediate dismissal from the audit team and may be prohibited from future participation in Compliance Monitoring and Enforcement Program activities by the Regional Entity or NERC.

2.2.7 NERC shall develop and provide training in auditing skills to all individuals prior to their participation in Certification evaluations. Training for Certification Team leaders shall be more comprehensive than the training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

2.4 An applicant that is determined to be competent to perform a function after completing all Certification requirements shall be deemed certified by NERC to perform that function for which it has demonstrated full competency.

2.4.1 All NERC certified entities shall be included on the NCR.

503. Regional Entity Implementation of Organization Registration and Organization Certification Program Requirements

1. **Delegation** — Recognizing the Regional Entity's knowledge of and experience with their members, NERC may delegate responsibility for Organization Registration and Organization Certification to the Regional Entity through a delegation agreement.

2. **Registration** — The following Organization Registration activities shall be managed by the Regional Entity per the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into the Rules of Procedure as Appendix 5A *Organization Registration and Organization Certification Manual*:

   2.1 Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4).

3. **Certification —** The following Organization Certification activities shall be managed by the Regional Entity in accordance with an approved delegation agreement or another applicable agreement:

   3.1 An entity seeking Certification to perform one of the functions requiring Certification shall contact the Regional Entity for the Region(s) in which it plans to operate to apply for Certification.

   3.2 An entity seeking Certification and other affected entities shall provide all information and data requested by NERC or the Regional Entity to conduct the Certification process.

   3.3 Regional Entities shall notify NERC of all Certification applicants.

   3.4 NERC and/or the Regional Entity shall evaluate the competency of entities requiring Certification to meet the NERC Certification requirements.

   3.5 NERC or the Regional Entity shall establish Certification procedures to include evaluation processes, schedules and deadlines, expectations of the applicants and all entities participating in the evaluation and Certification processes, and requirements for Certification Team members.

      3.5.1 The NERC / Regional Entity Certification procedures will include provisions for on-site visits to the applicant's facilities to review the data collected through questionnaires, interviewing the operations and management personnel, inspecting the facilities and equipment (including requesting a demonstration of all tools identified in the Certification process), reviewing all necessary documents and data (including all agreements, processes, and procedures identified in the Certification process), reviewing

Certification documents and projected system operator work schedules, and reviewing any additional documentation needed to support the completed questionnaire or inquiries arising during the site visit.

3.5.2 The NERC/ Regional Entity Certification procedures will provide for preparation of a written report by the Certification Team, detailing any deficiencies that must be resolved prior to granting Certification, along with any other recommendations for consideration by the applicant, the Regional Entity, or NERC.

504. Appeals

1. NERC shall maintain an appeals process to resolve any disputes related to Registration or Certification activities per the *Organization Registration and Organization Certification Manual,* which is incorporated in these Rules of Procedure as Appendix 5A.

2. The Regional Entity Certification appeals process shall culminate with the Regional Entity board or a committee established by and reporting to the Regional Entity board as the final adjudicator, provided that where applicable, Canadian provincial governmental authorities may act as the final adjudicator in their jurisdictions. NERC shall be notified of all appeals and may observe any proceedings **(Appendix 5A** *Organization Registration and Organization Certification Manual*).

505. Program Maintenance

NERC shall maintain its program materials, including such manuals or other documents as it deems necessary, of the governing policies and procedures of the Organization Registration and Organization Certification Programs.

506. Independent Audit of NERC Organization Registration and Organization Certification Program

1. NERC, through the Compliance and Certification Committee, shall provide for an independent audit of its Organization Registration and Organization Certification Programs at least once every three years, or more frequently, as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board.

2. The audit shall evaluate the success, effectiveness and consistency of the NERC Organization Registration and Organization Certification Programs.

3. The final report shall be posted by NERC for public viewing.

4. If the audit report includes recommendations to improve the program, the administrators of the program shall provide a written response to the Board within 30 days of the final report, detailing the disposition of each and every

recommendation, including an explanation of the reasons for rejecting a recommendation and an implementation plan for the recommendations accepted.

507. Provisions Relating to Joint Registration Organizations (JRO)

1. In addition to registering as the entity responsible for all functions that it performs itself, an entity may register as a JRO on behalf of one or more of its members or related entities for one or more functions for which such members or related entities would otherwise be required to register and, thereby, accept on behalf of such members or related entities all compliance responsibility for that function or those functions including all reporting requirements. Any entity seeking to register as a JRO must submit a written agreement with its members or related entities for all Requirements/sub-Requirements for the function(s) for which the entity is registering for and takes responsibility for, which would otherwise be the responsibility of one or more of its members or related entities. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the JRO Registration.

2. The JRO Registration data must include the same Registration information as a normal compliance Registration entry. The JRO is responsible for providing all of the information and data, including submitting reports, as needed by the Regional Entity for performing assessments of compliance.

3. The Regional Entity shall notify NERC of each JRO that the Regional Entity accepts. The notification will identify the point of contact and the functions(s) being registered for on behalf of its members or related entities.

4. For purposes of Compliance Audits, the Regional Entity shall keep a list of all JROs. This document shall contain a list of each JRO's members or related entities and the function(s) for which the JRO is registered for that member(s) or related entity(s). It is the responsibility of the JRO to provide the Regional Entity with this information as well as the applicable JRO agreement(s).

5. The Regional Entity may request clarification of any list submitted to it that identifies the members of the JRO and may request such additional information as the Regional Entity deems appropriate.

6. The Regional Entity's acceptance of a JRO shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded the JRO will meet the Registration requirements of Section 501(1.4).

7. NERC shall maintain, and post on its website, a JRO registry listing all JRO Registrations that have been reviewed and accepted by the Regional Entity. The posting shall identify the JRO entity taking compliance responsibilities for itself and its members.

8. The JRO shall inform the Regional Entity of any changes to an existing JRO. The Regional Entity shall promptly notify NERC of each such revision.

9. Nothing in Section 507 shall preclude a member of a JRO, a related entity, or any other entity from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards applicable to the function(s) for which the member or other entity is registering. A JRO member or related entity that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the JRO of its Registration.

508. Provisions Relating to Coordinated Functional Registration (CFR) Entities

1. In addition to registering as an entity responsible for all functions that it performs itself, multiple entities may each register using a CFR for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function. The CFR submission must include a written agreement that governs itself and clearly specifies the entities' respective compliance responsibilities. The Registration of the CFR is the complete Registration for each entity. Additionally, each entity shall take full compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements it has registered for in the CFR. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the CFR.

2. Each CFR or each individual entity within a CFR must identify a point of contact that is responsible for providing information and data, including submitting reports as needed by the Regional Entity related to the CFR Registration.

3. The Regional Entity shall notify NERC of each CFR that the Regional Entity accepts.

4. NERC or the Regional Entity may request clarification of any list submitted to it that identifies the compliance responsibilities of the CFR and may request such additional information as NERC or the Regional Entity deems appropriate.

5. The Regional Entity's acceptance of that CFR shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded the CFR will meet the Registration requirements of Section 501(1.4).

6. NERC shall maintain, and post on its website, a CFR registry listing all CFR Registrations that have been accepted by NERC or by a Regional Entity. The posting shall clearly list all the Reliability Standards or Requirements/sub-Requirements thereof for which each entity of the CFR is responsible for under the CFR.

7. The point of contact shall inform the Regional Entity of any changes to an existing CFR. The Regional Entity shall promptly notify NERC of each such revision.

8. In the event of a violation of a Reliability Standard or of a Requirement/sub-Requirement of a Reliability Standard for which an entity of a CFR is registered, that entity shall be identified in the Notice of Alleged Violation and shall be assessed the sanction or Penalty in accordance with the NERC Sanctions Guidelines. In the event a Regional Entity is not able to determine which entity(ies) is responsible for a particular Reliability Standard, or Requirements/sub-Requirements thereof that has been violated, the Regional Entity shall investigate the noncompliance in accordance with the NERC Rules of Procedure Section 400, *Compliance Enforcement*, to determine the entity(ies) to which the Regional Entity shall to issue the sanction or Penalty for the violation.

9. Nothing in Section 508 shall preclude an entity registered in a CFR, or any other entity from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards applicable to the function(s) for which the entity is registering. An entity registered in a CFR that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the point of contact of its Registration.

509. Exceptions to the Definition of the Bulk Electric System

An Element is considered to be (or not be) part of the Bulk Electric System by applying the BES Definition to the Element (including the inclusions and exclusions set forth therein). Appendix 5C sets forth the procedures by which (i) an entity may request a determination that an Element that falls within the definition of the Bulk Electric System should be exempted from being considered a part of the Bulk Electric System, or (ii) an entity may request that an Element that falls outside of the definition of the Bulk Electric System should be considered part of the Bulk Electric System.

SECTION 600 — PERSONNEL CERTIFICATION PROGRAM

601. Scope of Personnel Certification Program

Maintaining the reliability of the Bulk Power System through implementation of the Reliability Standards requires skilled, and qualified personnel, including system operators. NERC shall develop a Personnel Certification Program to:

1. Provide the mechanism to determine system operators' essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations;

2. administer a system operator Certification exam; and

3. award the system operator Certification Credential to individuals who pass the exam.

The NERC Personnel Certification Program shall be international in scope consistent with the ERO's international regulatory responsibility for the reliability of the Bulk Power System in North America.

NERC Reliability Standards define which system operators require certification pursuant to the NERC Personnel Certification Program.

The NERC Personnel Certification Governance Committee (PCGC) is the governing body that establishes the policies, sets fees, and monitors the performance of the Personnel Certification Program for system operators.

602. Structure of ERO Personnel Certification Program

The PCGC shall develop and update, as necessary, a manual which describes the following:

1. requirements for administering the system operator examinations;

2. requirements for exam eligibility;

3. requirements for awarding the Certification Credential;

4. requirements for Certification Credential maintenance;

5. dispute resolution procedures; and

6. disciplinary action guidelines.

603. Examination and Maintenance of NERC System Operator Certification Credentials

1. System operators seeking to obtain a Credential must pass an examination to earn the Credential.

2. A certificate will be issued to successful candidates which is valid for three years.

3. A system operator must earn Continuing Education Hours (CE Hours) in NERC-Approved Learning Activities within the three-year period preceding the expiration date of his/her certificate as determined by the PCGC and posted in the NERC System Operator Program Manual. A system operator must request a renewal and submit the appropriate fee for Certification renewal evaluation.

4. The Credential of a certified system operator who does not accumulate the required number and balance of CE Hours within the three-year period will be Suspended. A system operator with a Suspended certificate cannot perform any task that requires an operator to be NERC-certified. The system operator with a Suspended Credential will have up to twelve months to acquire the necessary CE Hours.

    4.1 During the time of suspension, the original anniversary date will be maintained. Therefore, should the system operator accumulate the required number of CE Hours within the twelve month suspension period, he/she will be issued a certificate that will be valid for three years from the previous expiration date.

    4.2 At the end of the twelve-month suspension period, if the system operator has not accumulated the required number of CE Hours, the Credential will be Revoked and all CE Hours earned will be forfeited. After a Credential is Revoked, the system operator will be required to pass an examination to become certified.

5. Hardship: Due to unforeseen events and extenuating circumstances, a certified system operator may be unable to accumulate the necessary CE Hours in the time frame required by the Personnel Certification Program to maintain the Credential. In such an event, the individual must submit a written request containing a thorough explanation of the circumstances and supporting information to the NERC Personnel Certification Manager. The PCGC retains the right to invoke this hardship clause as it deems appropriate to address such events or circumstances.

604. Dispute Resolution Process

1. Any dispute arising under the NERC agreement establishing the *NERC Personnel Certification Program* or from the establishment of any NERC rules, policies, or procedures dealing with any segment of the Certification process shall be subject to the NERC System Operator Certification Dispute Resolution Process. The Dispute Resolution Process is for the use of persons who hold an operator Certification or persons wishing to be certified to dispute the validity of the examination, the content of the test, the content outlines, or the Registration process.

2. Dispute Resolution Process consists of three steps.

2.1. Notify NERC Personnel Certification Program Staff: This first step can usually resolve the issues without further actions. It is expected that most disputes will be resolved at this step. If the issue(s) is not resolved to the satisfaction of the parties involved in the first step, the issue can be brought to the PCGC Dispute Resolution Task Force.

2.2. PCGC Dispute Resolution Task Force: If the NERC staff did not resolve the issue(s) to the satisfaction of the parties involved, a written request must be submitted to the chairman of the PCGC through NERC staff explaining the issue(s) and requesting further action. Upon receipt of the letter, the PCGC chairman will present the request to the PCGC Dispute Resolution Task Force for action. This task force consists of three current members of the PCGC. The PCGC Dispute Resolution Task Force will investigate and consider the issue(s) presented and make a decision. This decision will then be communicated to the submitting party, the PCGC chairman, and the NERC staff within 45 calendar days of receipt of the request.

3. Personnel Certification Governance Committee: If the PCGC Dispute Resolution Task Force's decision did not resolve the issue(s) to the satisfaction of the parties involved, the final step in the process is for the issue(s) to be brought before the PCGC. Within 45 days of the date of the Task Force's decision, the disputing party shall submit a written request to the PCGC chairman through NERC staff requesting that the issue(s) be brought before the PCGC for resolution. The chairman shall see that the necessary documents and related data are provided to the PCGC members as soon as practicable. The PCGC will then meet or conference to discuss the issue(s) and make their decision within 60 calendar days of the chairman's receipt of the request. The decision will be provided to the person bringing the issue(s) and the NERC staff. The PCGC is the governing body of the Certification program and its decision is final.

4. Dispute Resolution Process Expenses: All individual expenses associated with the Dispute Resolution Process, including salaries, meetings, or consultant fees, shall be the responsibility of the individual parties incurring the expense.

5. Decision Process: Robert's Rules of Order shall be used as a standard of conduct for the Dispute Resolution Process. A majority vote of the members present will decide all issues. The vote will be taken in a closed session. No member of the PCGC may participate in the Dispute Resolution Process, other than as a party or witness, if he or she has an interest in the particular matter.

5.1 A stipulation of invoking the Dispute Resolution Process is that the entity invoking the Dispute Resolution Process agrees that neither NERC (its members, Board of Trustees, committees, subcommittees, and staff), any person assisting in the Dispute Resolution Process, nor any company employing a person assisting in the Dispute Resolution Process, shall be liable, and they shall be held harmless against the consequences of or any

action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the Dispute Resolution Process. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

605. Disciplinary Action

1. Disciplinary action may be necessary to protect the integrity of the system operator Credential. The PCGC may initiate disciplinary action should an individual act in a manner that is inconsistent with expectations, including but not limited to:

    1.1. Willful, gross, and/or repeated violation of the NERC Reliability Standards as determined by a NERC investigation.

    1.2. Willful, gross, and/or repeated negligence in performing the duties of a certified system operator as determined by a NERC investigation.

    1.3. Intentional misrepresentation of information provided on a NERC application for a system operator Certification exam or to maintain a system operator Credential using CE Hours.

    1.4. Intentional misrepresentation of identification in the exam process, including a person identifying himself or herself as another person to obtain Certification for the other person.

    1.5. Any form of cheating during a Certification exam, including, but not limited to, bringing unauthorized reference material in the form of notes, crib sheets, or other methods of cheating into the testing center.

    1.6. A certified system operator's admission to or conviction of any felony or misdemeanor directly related to his/her duties as a system operator.

2. Hearing Process: Upon report to NERC of a candidate's or certified system operator's alleged misconduct, the NERC PCGC Credential Review Task Force will convene for the determination of facts. An individual, government agency, or other investigating authority can file a report. Unless the Task Force initially determines that the report of alleged misconduct is without merit, the candidate or certified system operator will be given the right to notice of the allegation. A hearing will be held and the charged candidate or certified system operator will be given an opportunity to be heard and present further relevant information. The Task Force may seek out information from other involved parties. The hearing will not be open to the public, but it will be open to the charged candidate or certified system operator and his or her representative. The Task Force will deliberate in a closed session, but the Task Force cannot receive any evidence during the closed session that was not developed during the course of the hearing.

3. Task Force's decision: The Task Force's decision will be unanimous and will be in writing with inclusion of the facts and reasons for the decision. The Task Force's written decision will be delivered to the PCGC and by certified post to the charged candidate or certified system operator. In the event that the Task Force is unable to reach a unanimous decision, the matter shall be brought to the full committee for a decision.

    3.1. No Action: Allegation of misconduct was determined to be unsubstantiated or inconsequential to the Credential.

    3.2. Probation: A letter will be sent from NERC to the offender specifying:

        3.2.1. The length of time of the probationary period (to be determined by the PCGC).

        3.2.2. Credential will remain valid during the probationary period.

        3.2.3. The probationary period does not affect the expiration date of the current certificate.

        3.2.4. During the probationary period, a subsequent offense of misconduct, as determined through the same process as described above, may be cause for more serious consequences.

    3.3. Revoke for Cause: A letter will be sent from NERC to the offender specifying:

        3.3.1. The length of time of the probationary period (to be determined by the PCGC).

        3.3.2. Credential is no longer valid.

        3.3.3. Successfully passing an exam will be required to become recertified.

        3.3.4. An exam will not be authorized until the revocation period expires

    3.4. Termination of Credential: A letter will be sent from NERC to the offender specifying permanent removal of Credential.

4. Credential Review Task Force: The Credential Review Task Force shall be comprised of three active members of the PCGC assigned by the Chairman of the PCGC on an ad hoc basis. No one on the Credential Review Task Force may have an interest in the particular matter. The Task Force will meet in a venue determined by the Task Force chairman.

5. Appeal Process: The decision of the Task Force may be appealed using the NERC System Operator Certification Dispute Resolution Process.

606. Candidate Testing

1. The PCGC shall develop exams to evaluate individual competence in a manner that is objective, and fair to all candidates, and to determine essential knowledge relating to NERC Reliability Standards as well as principles of the Bulk Power System operations.

2. The PCGC shall oversee exam administration as follows:

   2.1 Adopt and implement a formal policy of periodic review of exams to assess ongoing relevance to knowledge and skill needed in the discipline; and

   2.2 Conduct ongoing studies to substantiate the reliability and validity of exams.

3. The PCGC shall develop and utilize policies and procedures to ensure the integrity and security of exams and the transparency of test administration consistent with the following:

   3.1 The PCGC shall establish pass/fail levels that protect the public with a method that is based on competence and generally accepted standards in the psychometric community as being fair and reasonable;

   3.2 The PCGC shall conduct ongoing studies to substantiate the reliability and validity of the exams;

   3.3 The PCGC shall dictate how long examination records are kept in their original format; and

   3.4 The PCGC shall demonstrate that different revisions of the exams assess equivalent content.

607. Public Information About the Personnel Certification Program

The PCGC shall maintain and publish the following:

1. a summary of the information, knowledge, or functions covered by each examination administered pursuant to the Personnel Certification Program; and

2. an annual summary of Certification activities for the Personnel Certification Program, including, the number of examinations delivered, the number of applicants who passed, the number of applicants who failed, and the number of applicants certified.

608. Responsibilities to Applicants for Certification or Re-Certification

The PCGC shall adhere to the following with respect to personnel applicants:

1. comply with all requirements of applicable federal and state/provincial laws with respect to all Certification and re-Certification activities, and shall require compliance of all contractors and/or providers of services;

2. make available to all applicants copies of formalized procedures for application for, and attainment of, personnel Certification and re-Certification and shall uniformly follow and enforce such procedures for all applicants;

3. implement a formal policy for the periodic review of eligibility criteria and application procedures for fairness;

4. provide competently proctored examination sites; and

5. uniformly provide applicants with examination results and give content summary after the examination.

609. Responsibilities to Employers of Certified Personnel

The PCGC shall adhere to the following with respect to certified personnel:

1. demonstrate that the exams adequately measure essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations;

2. award Certification and re-Certification only after the skill and knowledge of the individual have been evaluated and determined to be acceptable;

3. maintain, in an electronic format, a current list of those personnel certified in the programs and have policies and procedures that delineate what information about a Certification Credential holder may be made public and under what circumstances; and

4. develop formal policies and procedures for discipline of a Certification Credential holder, including the revocation of the certificate, for conduct deemed harmful to the public or inappropriate to the discipline (e.g., incompetence, unethical behavior, physical or mental impairment affecting performance). These procedures shall incorporate due process.

SECTION 700 — RELIABILITY READINESS EVALUATION AND IMPROVEMENT AND FORMATION OF SECTOR FORUMS

701. Confidentiality Requirements for Readiness Evaluations and Evaluation Team Members

1. All information made available or created during the course of any reliability readiness evaluation including, but not limited to, data, Documents, observations and notes, shall be maintained as confidential by all evaluation team members, in accordance with the requirements of Section 1500.

2. Evaluation team members are obligated to destroy all confidential evaluation notes following the posting of the final report of the reliability readiness evaluation.

3. NERC will retain reliability readiness evaluation-related documentation, notes, and materials for a period of time as defined by NERC.

4. These confidentiality requirements shall survive the termination of the NERC Reliability Readiness Evaluation and Improvement Program.

702. Formation of Sector Forum

1. NERC will form a sector forum at the request of any five members of NERC that share a common interest in the safety and reliability of the Bulk Power System. The members of sector forum may invite such others of the members of NERC to join the sector forum as the sector forum deems appropriate.

2. The request to form a sector forum must include a proposed charter for the sector forum. The Board must approve the charter.

3. NERC will provide notification of the formation of a sector forum to its membership roster. Notices and agendas of meetings shall be posted on NERC's website.

4. A sector forum may make recommendations to any of the NERC committees and may submit a Standards Authorization Request to the NERC *Reliability Standards Development Procedure*.

SECTION 800 — RELIABILITY ASSESSMENT AND PERFORMANCE ANALYSIS

801. Objectives of the Reliability Assessment and Performance Analysis Program

The objectives of the NERC Reliability Assessment and Performance Analysis Program are to: (1) conduct, and report the results of, an independent assessment of the overall reliability and adequacy of the interconnected North American Bulk Power Systems, both as existing and as planned; (2) analyze off-normal events on the Bulk Power System; (3) identify the root causes of events that may be precursors of potentially more serious events; (4) assess past reliability performance for lessons learned; (5) disseminate findings and lessons learned to the electric industry to improve reliability performance; and (6) develop reliability performance benchmarks. The final reliability assessment reports shall be approved by the Board for publication to the electric industry and the general public.

802. Scope of the Reliability Assessment Program

1. The scope of the Reliability Assessment Program shall include:

    1.1 Review, assess, and report on the overall electric generation and transmission reliability (adequacy and operating reliability) of the interconnected Bulk Power Systems, both existing and as planned.

    1.2 Assess and report on the key issues, risks, and uncertainties that affect or have the potential to affect the reliability of existing and future electric supply and transmission.

    1.3 Review, analyze, and report on Regional Entity self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.

    1.4 Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on Bulk Power System reliability.

    1.5 Investigate, assess, and report on the potential impacts of new and evolving electricity market practices, new or proposed regulatory procedures, and new or proposed legislation (e.g. environmental requirements) on the adequacy and operating reliability of the Bulk Power Systems.

2. The Reliability Assessment Program shall be performed in a manner consistent with the Reliability Standards of NERC including but not limited to those that specify reliability assessment Requirements.

803. Reliability Assessment Reports

The number and type of periodic assessments that are to be conducted shall be at the discretion of NERC. The results of the reliability assessments shall be documented in three reports: the long-term and the annual seasonal (summer) and the annual seasonal (winter) assessment reports. NERC shall also conduct special reliability assessments from time to time as circumstances warrant. The reliability assessment reports shall be reviewed and approved for publication by the Board. The three regular reports are described below.

1. **Long-Term Reliability Assessment Report** — The annual long-term report shall cover a ten-year planning horizon. The planning horizon of the long-term reliability assessment report shall be subject to change at the discretion of NERC. Detailed generation and transmission adequacy assessments shall be conducted for the first five years of the review period. For the second five years of the review period, the assessment shall focus on the identification, analysis, and projection of trends in peak demand, electric supply, and transmission adequacy, as well as other industry trends and developments that may impact future electric system reliability. Reliability issues of concern and their potential impacts shall be presented along with any mitigation plans or alternatives. The long-term reliability assessment reports will generally be published in the fall (September) of each year. NERC will also publish electricity supply and demand data associated with the long-term reliability assessment report.

2. **Summer Assessment Report** — The annual summer seasonal assessment report typically shall cover the four-month (June–September) summer period. It shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected summer peak demands. It shall also identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may include possible mitigation alternatives. The report will generally be published in mid-May for the upcoming summer period.

3. **Winter Assessment Report** — The annual winter seasonal assessment report shall cover the three-month (December–February) winter period. The report shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected winter peak demands. Similar to the summer assessment, the winter assessment shall identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may also include possible mitigation alternatives. The winter assessment report will generally be published in mid-November for the upcoming winter period.

4. **Special Reliability Assessment Reports** — In addition to the long-term and seasonal reliability assessment reports, NERC shall also conduct special reliability assessments on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the Board or governmental authorities. The teams of reliability and technical experts also may initiate special assessments of key

reliability issues and their impacts on the reliability of a regions, subregions, or Interconnection (or a portion thereof). Such special reliability assessments may include, among other things, operational reliability assessments, evaluations of emergency response preparedness, adequacy of fuel supply, hydro conditions, reliability impacts of new or proposed environmental rules and regulations, and reliability impacts of new or proposed legislation that affects or has the potential to affect the reliability of the interconnected Bulk Power Systems in North America.

804. Reliability Assessment Data and Information Requirements

To carry out the reviews and assessments of the overall reliability of the interconnected Bulk Power Systems, the Regional Entities and other entities shall provide sufficient data and other information requested by NERC in support of the annual long-term and seasonal assessments and any special reliability assessments.

Some of the data provided for these reviews and assessment may be considered confidential from a competitive marketing perspective, a Critical Energy Infrastructure Information perspective, or for other purposes. Such data shall be treated in accordance with the provisions of Section 1500 – Confidential Information.

While the major sources of data and information for this program are the Regional Entities, a team of reliability and technical experts is responsible for developing and formulating its own independent conclusions about the near-term and long-term reliability of the Bulk Power Systems.

In connection with the reliability assessment reports, requests shall be submitted to each of the Regional Entities for required reliability assessment data and other information, and for each Regional Entity's self-assessment report. The timing of the requests will be governed by the schedule for the preparation of the assessment reports.

The Regional Entity self-assessments are to be conducted in compliance with NERC Reliability Standards and the respective regional planning criteria. The team(s) of reliability and technical experts shall also conduct interviews with the Regional Entities as needed. The summary of the Regional Entity self-assessments that are to be included in the assessment reports shall follow the general outline identified in NERC's request. This outline may change from time to time as key reliability issues change.

In general, the Regional Entity reliability self-assessments shall address, among other areas, the following topics: demand and Net Energy for Load; assessment of projected resource adequacy; any transmission constraints that may impact bulk transmission adequacy and plans to alleviate those constraints; any unusual operating conditions that could impact reliability for the assessment period; fuel supply adequacy; the deliverability of generation (both internal and external) to Load; and any other reliability issues in the Region and their potential impacts on the reliability of the Bulk Power Systems.

805. Reliability Assessment Process

Based on their expertise, the review of the collected data, the review of the Regional Entity self-assessment reports, and interviews with the Regional Entities, as appropriate, the teams of reliability and technical experts shall perform an independent review and assessment of the generation and transmission adequacy of each Region's existing and planned Bulk Power System. The results of the review teams shall form the basis of NERC's long-term and seasonal reliability assessment reports. The review and assessment process is briefly summarized below.

1. **Resource Adequacy Assessment** — The teams shall evaluate the regional demand and resource capacity data for completeness in the context of the overall resource capacity needs of the Region. The team shall independently evaluate the ability of the Regional Entity members to serve their obligations given the demand growth projections, the amount of existing and planned capacity, including committed and uncommitted capacity, contracted capacity, or capacity outside of the Region. If the Region relies on capacity from outside of the Region to meet its resource objectives, the ability to deliver that capacity shall be factored into the assessment. The demand and resource capacity information shall be compared to the resource adequacy requirements of the Regional Entity for the year(s) or season(s) being assessed. The assessment shall determine if the resource information submitted represents a reasonable and attainable plan for the Regional Entity and its members. For cases of inadequate capacity or reserve margin, the Regional Entity will be requested to analyze and explain any resource capacity inadequacies and its plans to mitigate the reliability impact of the potential inadequacies. The analysis may be expanded to include surrounding areas. If the expanded analysis indicates further inadequacies, then an interregional problem may exist and will be explored with the applicable Regions. The results of these analyses shall be described in the assessment report.

2. **Transmission Adequacy and Operating Reliability Assessment** — The teams shall evaluate transmission system information that relates to the adequacy and operating reliability of the regional transmission system. That information shall include: regional planning study reports, interregional planning study reports, and/or regional operational study reports. If additional information is required, another data request shall be sent to the Regional Entity. The assessment shall provide a judgment on the ability of the regional transmission system to operate reliably under the expected range of operating conditions over the assessment period as required by NERC Reliability Standards. If sub-areas of the regional system are especially critical to the Reliable Operation of the regional bulk transmission system, these Facilities or sub-areas shall be reviewed and addressed in the assessment. Any areas of concern related to the adequacy or operating reliability of the system shall be identified and reported in the assessment.

3. **Seasonal Operating Reliability Assessment** — The team(s) shall evaluate the overall operating reliability of the regional bulk transmission systems. In areas with potential resource adequacy or system operating reliability problems,

operational readiness of the affected Regional Entities for the upcoming season shall be reviewed and analyzed. The assessment may consider unusual but possible operating scenarios and how the system is expected to perform. Operating reliability shall take into account a wide range of activities, all of which should reinforce the Regional Entity's ability to deal with the situations that might occur during the upcoming season. Typical activities in the assessment may include: facility modifications and additions, new or modified operating procedures, emergency procedures enhancement, and planning and operating studies. The teams shall report the overall seasonal operating reliability of the regional transmission systems in the annual summer and winter assessment reports.

4. **Reporting of Reliability Assessment Results** — The teams of reliability and technical experts shall provide an independent assessment of the reliability of the Regional Entities and the North American interconnected Bulk Power System for the period of the assessment. While the Regional Entities are relied upon to provide the information to perform such assessments, the review team is not required to accept the conclusions provided by the Regional Entities. Instead, the review team is expected, based on their expertise, to reach their own independent conclusions about the status of the adequacy of the generation and bulk power transmission systems of North America.

   The review team also shall strive to achieve consensus in their assessments. The assessments that are made are based on the best information available at the time. However, since judgment is applied to this information, legitimate differences of opinion can develop. Despite these differences, the review team shall work to achieve consensus on their findings.

   In addition to providing long-term and seasonal assessments in connection with the Reliability Assessment Program, the review team of experts shall also be responsible for recommending new and revised Reliability Standards related to the reliability assessments and the reliability of the Bulk Power Systems. These proposals for new or revised Reliability Standards shall be entered into NERC's Reliability Standards development process.

   Upon completion of the assessment, the team shall share the results with the Regional Entities. The Regional Entities shall be given the opportunity to review and comment on the conclusions in the assessment and to provide additional information as appropriate. The reliability assessments and their conclusions are the responsibility of NERC's technical review team and NERC.

   The preparation and approval of NERC's reliability assessment reports shall follow a prescribed schedule including review, comment, and possible approval by appropriate NERC committees. The long-term and seasonal (summer and winter) reliability assessment reports shall be further reviewed for approval by the Board for publication to the electric industry.

806. Scope of the Reliability Performance and Analysis Program

The components of the program will include analysis of large-scale outages, disturbances, and near misses to determine root causes and lessons learned; identification and continuous monitoring of performance indices to detect emerging trends and signs of a decline in reliability performance; and communications of performance results, trends, recommendations, and initiatives to those responsible to take actions; followed with confirmation of actions to correct any deficiencies identified. Within NERC, the reliability performance program will provide performance results to the Reliability Standards Development and Compliance Monitoring and Enforcement Programs to make the necessary adjustments to preserve reliability based on a risk-based approach.

807. Analysis of Major Events

Responding to major events affecting the Bulk Power System such as significant losses of Load or generation, significant Bulk Power System disturbances, or other emergencies on the Bulk Power System, can be divided into four phases: situational assessment and communications; situation tracking and communications; data collection, investigation, analysis, and reporting; and follow-up on recommendations.

1. NERC's role following a major event is to provide leadership, coordination, technical expertise, and assistance to the industry in responding to the major event. Working closely with the Regional Entities and Reliability Coordinators, and other appropriate Registered Entities, NERC will coordinate and facilitate efforts among industry participants, and with state, federal, and provincial governments in the United States and Canada to support the industry's response.

2. When responding to any major event where physical or cyber security is suspected as a cause or contributing factor to the major event, NERC will immediately notify appropriate government agencies and coordinate its activities with them.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator of the Bulk Power System shall also provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entity as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

4. During the conduct of NERC analyses, assistance may be needed from government agencies. This assistance could include: authority to require data reporting from affected or involved parties; communications with other agencies of government; investigations related to possible criminal or terrorist involvement in the major event; resources for initial data gathering immediately after the major

event; authority to call meetings of affected or involved parties; and technical and analytical resources for studies.

5. NERC shall work with all other participants to establish a clear delineation of roles, responsibilities, and coordination requirements among industry and government for the investigation and reporting of findings, conclusions, and recommendations related to major events with the objective of avoiding, to the extent possible, multiple investigations of the same major event. If the major event is confined to a single Regional Entity, NERC representatives will participate as members of the Regional Entity analysis team. NERC will establish, maintain, and revise from time to time as appropriate based on experience, a manual setting forth procedures and protocols for communications and sharing and exchange of information between and among NERC, the affected Regional Entity or Entities, and relevant governmental authorities, industry organizations and Bulk Power System user, owners, and operators concerning the investigation and analysis of major events.

6. NERC and applicable entity(s) will apply, as appropriate to the circumstances of the major event, the NERC *Blackout and Disturbance Response Procedures*, which are incorporated into these Rules of Procedure as **Appendix 8**. These procedures provide a framework to guide NERC's response to major events that may have multiregional, national, or international implications. Experienced industry leadership shall be applied to tailor the response to the specific circumstances of the major event. In accordance with those procedures, the NERC president will determine whether the major event warrants analysis at the NERC level. A Regional Entity may request that NERC elevate any analysis of a major event to the NERC level.

7. NERC will screen and analyze the findings and recommendations from the analysis, and those with generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

808. Analysis of Off-Normal Occurrences, Bulk Power System Performance, and Bulk Power System Vulnerabilities

1. NERC and Regional Entities will analyze Bulk Power System and equipment performance occurrences that do not rise to the level of a major event, as described in Section 807. NERC and Regional Entities will also analyze potential vulnerabilities in the Bulk Power System that they discover or that are brought to their attention by other sources including government agencies. The purpose of these analyses is to identify the root causes of occurrences or conditions that may be precursors of major events or other potentially more serious occurrences, or that have the potential to cause major events or other more serious occurrences, to assess past reliability performance for lessons learned, and to develop reliability performance benchmarks and trends.

2. NERC and Regional Entities will screen and analyze off-normal occurrences, Bulk Power System performance, and potential Bulk Power System vulnerabilities for significance, and information from those indicated as having generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator, of the Bulk Power System shall provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entities as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

809. Reliability Benchmarking

NERC shall identify and track key reliability indicators as a means of benchmarking reliability performance and measuring reliability improvements. This program will include assessing available metrics, developing guidelines for acceptable metrics, maintaining a performance metrics "dashboard" on the NERC website, and developing appropriate reliability performance benchmarks.

810. Information Exchange and Issuance of NERC Advisories, Recommendations and Essential Actions

1. Members of NERC and Bulk Power System owners, operators, and users shall provide NERC with detailed and timely operating experience information and data.

2. In the normal course of operations, NERC disseminates the results of its events analysis findings, lessons learned and other analysis and information gathering to the industry. These findings, lessons learned and other information will be used to guide the Reliability Assessment Program.

3. When NERC determines it is necessary to place the industry or segments of the industry on formal notice of its findings, analyses, and recommendations, NERC will provide such notification in the form of specific operations or equipment Advisories, Recommendations or Essential Actions:

   3.1 Level 1 (Advisories) – purely informational, intended to advise certain segments of the owners, operators and users of the Bulk Power System of findings and lessons learned;

   3.2 Level 2 (Recommendations) – specific actions that NERC is recommending be considered on a particular topic by certain segments of

owners, operators, and users of the Bulk Power System according to each entity's facts and circumstances;

3.3 Level 3 (Essential Actions) – specific actions that NERC has determined are essential for certain segments of owners, operators, or users of the Bulk Power System to take to ensure the reliability of the Bulk Power System. Such Essential Actions require NERC Board approval before issuance.

4. The Bulk Power System owners, operators, and users to which Level 2 (Recommendations) and Level 3 (Essential Actions) notifications apply are to evaluate and take appropriate action on such issuances by NERC. Such Bulk Power System owners, operators, and users shall also provide reports of actions taken and timely updates on progress towards resolving the issues raised in the Recommendations and Essential Actions in accordance with the reporting date(s) specified by NERC.

5. NERC will advise the Commission and other Applicable Governmental Authorities of its intent to issue all Level 1 (Advisories), Level 2 (Recommendations), and Level 3 (Essential Actions) at least five (5) business days prior to issuance, unless extraordinary circumstances exist that warrant issuance less than five (5) business days after such advice. NERC will file a report with the Commission and other Applicable Governmental Authorities no later than thirty (30) days following the date by which NERC has requested the Bulk Power System owners, operators, and users to which a Level 2 (Recommendation) or Level 3 (Essential Action) issuance applies to provide reports of actions taken in response to the notification. NERC's report to the Commission and other Applicable Governmental Authorities will describe the actions taken by the relevant owners, operators, and users of the Bulk Power System and the success of such actions taken in correcting any vulnerability or deficiency that was the subject of the notification, with appropriate protection for Confidential Information or Critical Energy Infrastructure Information.

811. Equipment Performance Data

Through its Generating Availability Data System (GADS), NERC shall collect operating information about the performance of electric generating equipment; provide assistance to those researching information on power plant outages stored in its database; and support equipment reliability as well as availability analyses and other decision-making processes developed by GADS subscribers. GADS data is also used in conducting assessments of generation resource adequacy.

SECTION 900 — TRAINING AND EDUCATION

901. Scope of the Training and Education Program

Assuring the Reliable Operation of the North American Bulk Power System requires informed knowledgeable and skilled personnel. NERC shall develop a program to oversee the coordination and delivery of learning materials, resources, and activities to allow for training and education of:

1. ERO Enterprise staff supporting statutory and delegation-related activities; and

2. Bulk Power System industry participants consistent with ERO functional program requirements.

902. Continuing Education Program

1. NERC shall develop and and maintain a continuing education program to approve those activities and entities meeting NERC continuing education requirements.

2. The Personnel Subcommittee (PS), which reports to the NERC Operating Committee, is the governing body of the NERC Continuing Education Program that oversees development and implementation of the Continuing Education Program requirements.

3. The PS shall develop and update, as necessary, a manual, approved by the Operating Committee, which describes the following:

    3.1 Requirements for approving contining education Providers and activities;

    3.2 Requirements for auditing continuing education Providers and activities;

    3.3 Multi-layer review process for disputed application reviews, interpretations of guideline and standards, probation or suspension of NERC-approved Provider status, and Continuing Education Hour disputes; and

    3.4 Requirements on fees for continuing education Providers and activities.

SECTION 1000 — SITUATION AWARENESS AND INFRASTRUCTURE SECURITY

1001. Situation Awareness

NERC shall through the use of Reliability Coordinators and available tools, monitor present conditions on the Bulk Power System and provide leadership coordination, technical expertise, and assistance to the industry in responding to events as necessary. To accomplish these goals, NERC will:

1. Maintain real-time situation awareness of conditions on the Bulk Power System;

2. Notify the industry of significant Bulk Power System events that have occurred in one area, and which have the potential to impact reliability in other areas;

3. Maintain and strengthen high-level communication, coordination, and cooperation with governments and government agencies regarding real-time conditions; and

4. Enable the Reliable Operation of interconnected Bulk Power Systems by facilitating information exchange and coordination among reliability service organizations.

1002. Reliability Support Services

NERC may assist in the development of tools and other support services for the benefit of Reliability Coordinators and other system operators to enhance reliability, operations and planning. NERC will work with the industry to identify new tools, collaboratively develop requirements, support development, provide an incubation period, and at the end of that period, transition the tool or service to another group or owner for long term operation of the tool or provision of the service. To accomplish this goal, NERC will:

1. Collaborate with industry to determine the necessity of new tools or services to enhance reliability;

2. For those tools that the collaborative process determines should proceed to a development phase, provide a start-up mechanism and development system;

3. Implement the tool either on its own or through an appropriate group or organization; and

4. Where NERC conducts the implementation phase of a new tool or service, develop a transition plan to turn maintenance and provision of the tool or service over to an organization identified in the development stage.

In addition to tools developed as a result of a collaborative process with industry, NERC may develop reliability tools on its own, but will consult with industry concerning the need for the tool prior to proceeding to development.

Tools and services being maintained by NERC as of January 1, 2012, will be reviewed and, as warranted, transitioned to an appropriate industry group or organization. NERC will develop and maintain a strategic reliability tools plan that will list the tools and services being maintained by NERC, and, where applicable, the plans for transition to an appropriate industry group or organization.

1003. Infrastructure Security Program

NERC shall coordinate electric industry activities to promote Critical Infrastructure protection of the Bulk Power System in North America by taking a leadership role in Critical Infrastructure protection of the electricity sector so as to reduce vulnerability and improve mitigation and protection of the electricity sector's Critical Infrastructure. To accomplish these goals, NERC shall perform the following functions.

1. Electric Sector Information Sharing and Analysis Center (ESISAC)

    1.1 NERC shall serve as the electricity sector's sector coordinator and operate its Information Sharing and Analysis Center to gather information and communicate security-related threats and incidents within the sector, with United States and Canadian government agencies, and with other Critical Infrastructure sectors.

    1.2 NERC shall improve the capability of the ESISAC to analyze security threats and incident information and provide situational assessments for the electricity sector and governments.

    1.3 NERC shall work closely with the United States Department of Homeland Security, Department of Energy, Natural Resources Canada, and Public Safety and Emergency Preparedness Canada.

    1.4 NERC shall strengthen and expand these functions and working relationships with the electricity sector, other Critical Infrastructure industries, governments, and government agencies throughout North America to ensure the protection of the infrastructure of the Bulk Power System.

    1.5 NERC shall fill the role of the Electricity Sector Coordinating Council and coordinate with the Government Coordinating Council.

    1.6 NERC shall coordinate with other Critical Infrastructure sectors through active participation with the other Sector Coordinating Councils, the other ISACs, and the National Infrastructure Advisory Committee.

    1.7 NERC shall encourage and participate in coordinated Critical Infrastructure protection exercises, including interdependencies with other Critical Infrastructure sectors.

2. Security Planning

2.1 NERC shall take a risk management approach to Critical Infrastructure protection, considering probability and severity, and recognizing that mitigation and recovery can be practical alternatives to prevention.

2.2 NERC shall keep abreast of the changing threat environment through collaboration with government agencies.

2.3 NERC shall develop criteria to identify critical physical and cyber assets, assess security threats, identify risk assessment methodologies, and assess effectiveness of physical and cyber protection measures.

2.4 NERC shall enhance and maintain the Bulk Power System critical spare transformer program, encourage increased participation by asset owners, and continue to assess the need to expand this program to include other critical Bulk Power System equipment.

2.5 NERC shall support implementation of the Critical Infrastructure Protection Standards through education and outreach.

2.6 NERC shall review and improve existing security guidelines, develop new security guidelines to meet the needs of the electricity sector, and consider whether any guidelines should be developed into Reliability Standards.

2.7 NERC shall conduct education and outreach initiatives to increase awareness and respond to the needs of the electricity sector.

2.8 NERC shall strengthen relationships with federal, state, and provincial government agencies on Critical Infrastructure protection matters.

2.9 NERC shall maintain and improve mechanisms for the sharing of sensitive or classified information with federal, state, and provincial government agencies on Critical Infrastructure protection matters; work with DOE and DHS to implement the National Infrastructure Protection Plan, as applicable to the electricity sector; and coordinate this work with PSEPC.

2.10 NERC shall improve methods to better assess the impact of a possible physical attack on the Bulk Power System and means to deter, mitigate, and respond following an attack.

2.11 NERC shall assess the results of vulnerability assessments and enhance the security of system control and data acquisition (SCADA) and process control systems by developing methods to detect an emerging cyber attack and the means to mitigate impacts on the Bulk Power Systems.

2.12 NERC shall work with the National SCADA Test Bed and the Process Control Systems Forum to accelerate the development of technology that will enhance the security, safety, and reliability of process control and SCADA systems.

SECTION 1100 — ANNUAL NERC BUSINESS PLANS AND BUDGETS

1101. Scope of Business Plans and Budgets

The Board shall determine the content of the budgets to be submitted to the Applicable Governmental Authorities with consultation from the members of the Member Representatives Committee, Regional Entities, and others in accordance with the Bylaws. The Board shall identify any activities outside the scope of NERC's statutory reliability functions, if any, and the appropriate funding mechanisms for those activities.

1102. NERC Funding and Cost Allocation

1. In order that NERC's costs shall be fairly allocated among Interconnections and among Regional Entities, the NERC funding mechanism for all statutory functions shall be based on Net Energy for Load (NEL).

2. NERC's costs shall be allocated so that all Load (or, in the case of costs for an Interconnection or Regional Entity, all Load within that Interconnection or Regional Entity) bears an equitable share of such costs based on NEL.

3. Costs shall be equitably allocated between countries or Regional Entities thereof for which NERC has been designated or recognized as the Electric Reliability Organization.

4. Costs incurred to accomplish the statutory functions for one Interconnection, Regional Entity, or group of entities will be directly assigned to that Interconnection, Regional Entity, or group of entities provided that such costs are allocated equitably to end-users based on Net Energy for Load.

1103. NERC Budget Development

1. The NERC annual budget process shall be scheduled and conducted for each calendar year so as to allow a sufficient amount of time for NERC to receive Member inputs, develop the budget, and receive Board and, where authorized by applicable legislation or agreement, Applicable Governmental Authority approval of the NERC budget for the following fiscal year, including timely submission of the proposed budget to FERC for approval in accordance with FERC regulations.

2. The NERC budget submittal to Applicable Governmental Authorities shall include provisions for all ERO functions, all Regional Entity delegated functions as specified in delegation agreements and reasonable reserves and contingencies.

3. The NERC annual budget submittal to Applicable Governmental Authorities shall include description and explanation of NERC's proposed ERO program activities for the year; budget component justification based on statutory or other authorities; explanation of how each budgeted activity lends itself to the accomplishment of the statutory or other authorities; sufficiency of resources provided for in the budget to carry out the ERO program responsibilities; explanation of the calculations and

budget estimates; identification and explanation of changes in budget components from the previous year's budget; information on staffing and organization charts; and such other information as is required by FERC and other Applicable Governmental Authorities having authority to approve the proposed budget.

4. NERC shall develop, in consultation with the Regional Entities, a reasonable and consistent system of accounts, to allow a meaningful comparison of actual results at the NERC and Regional Entity level by the Applicable Governmental Authorities.

1104. Submittal of Regional Entity Budgets to NERC

1. Each Regional Entity shall submit its proposed annual budget for carrying out its delegated authority functions as well as all other activities and funding to NERC in accordance with a schedule developed by NERC and the Regional Entities, which shall provide for the Regional Entity to submit its final budget that has been approved by its board of directors or other governing body no later than July 1 of the prior year, in order to provide sufficient time for NERC's review and comment on the proposed budget and approval of the Regional Entity budget by the NERC Board of Trustees in time for the NERC and Regional Entity budgets to be submitted to FERC and other Applicable Governmental Authorities for approval in accordance with their regulations. The Regional Entity's budget shall include supporting materials in accordance with the budget and reporting format developed by NERC and the Regional Entities, including the Regional Entity's complete business plan and organization chart, explaining the proposed collection of all dues, fees, and charges and the proposed expenditure of funds collected in sufficient detail to justify the requested funding collection and budget expenditures.

2. NERC shall review and approve each Regional Entity's budget for meeting the requirements of its delegated authority. Concurrent with approving the NERC budget, NERC shall review and approve, or reject, each Regional Entity budget for filing.

3. NERC shall also have the right to review from time to time, in reasonable intervals but no less frequently than every three years, the financial books and records of each Regional Entity having delegated authority in order to ensure that the documentation fairly represents in all material aspects appropriate funding of delegated functions.

1105. Submittal of NERC and Regional Entity Budgets to Governmental Authorities for Approval

1. NERC shall file for approval by the Applicable Governmental Authorities at least 130 days in advance of the start of each fiscal year. The filing shall include: (1) the complete NERC and Regional Entity budgets including the business plans and organizational charts approved by the Board, (2) NERC's annual funding requirement (including Regional Entity costs for delegated functions), and (3) the mechanism for assessing charges to recover that annual funding requirement,

together with supporting materials in sufficient detail to support the requested funding requirement.

2. NERC shall seek approval from each Applicable Governmental Authority requiring such approval for the funding requirements necessary to perform ERO activities within their jurisdictions.

1106. NERC and Regional Entity Billing and Collections

1. NERC shall request the Regional Entities to identify all Load-Serving Entities[3] within each Regional Entity and the NEL assigned to each Load-Serving Entity, and the Regional Entities shall supply the requested information. The assignment of a funding requirement to an entity shall not be the basis for determining that the entity must be registered in the Compliance Registry.

2. NERC shall accumulate the NEL by Load-Serving Entities for each Applicable Governmental Authority and submit the proportional share of NERC funding requirements to each Applicable Governmental Authority for approval together with supporting materials in sufficient detail to support the requested funding requirement.

3. NEL reported by Balancing Authorities within a Region shall be used to rationalize and validate amounts allocated for collection through Regional Entity processes.

4. The billing and collection processes shall provide:

   4.1 A clear validation of billing and application of payments.

   4.2 A minimum of data requests to those being billed.

   4.3 Adequate controls to ensure integrity in the billing determinants including identification of entities responsible for funding NERC's activities.

   4.4 Consistent billing and collection terms.

5. NERC will bill and collect all budget requirements approved by Applicable Governmental Authorities (including the funds required to support those functions assigned to the Regional Entities through the delegation agreements) directly from the Load-Serving Entities or their designees or as directed by particular Applicable Governmental Authorities, except where the Regional Entity is required to collect the budget requirements for NERC, in which case the Regional Entity will collect directly from the Load-Serving Entities or as otherwise provided by agreement and submit funds to NERC. Alternatively, a load-serving

[3] A Regional Entity may allocate funding obligations using an alternative method approved by NERC and by FERC and other Applicable Governmental Authorities, as provided for in the regional delegation agreement.

entity may pay its allocated ERO costs through a Regional Entity managed collection mechanism.

6. NERC shall set a minimum threshold limit on the billing of small LSEs to minimize the administrative burden of collection.

7. NERC shall pursue any non-payments and shall request assistance from Applicable Governmental Authorities as necessary to secure collection.

8. In the case where a Regional Entity performs the collection for ERO, the Regional Entity will not be responsible for non-payment in the event that a user, owner or operator of the Bulk Power System does not pay its share of dues, fees and charges in a timely manner, provided that such a Regional Entity shall use reasonably diligent efforts to collect dues, fees, and other charges from all entities obligated to pay them. However, any revenues not paid shall be recovered from others within the same Region to avoid cross-subsidization between Regions.

9. Both NERC and the Regional Entities also may bill members or others for functions and services not within statutory requirements or otherwise authorized by the Applicable Governmental Authorities. Costs and revenues associated with these functions and services shall be separately identified and not commingled with billings associated with the funding of NERC or of the Regional Entities for delegated activities.

1107. Penalty Applications

1. Where NERC or a Regional Entity initiates a compliance monitoring and enforcement process that leads to imposition of a Penalty, the entity that initiated the process shall receive any Penalty monies imposed and collected as a result of that process, unless a different disposition of the Penalty monies is provided for in the delegation agreement, or in a contract or a disposition of the violation that is approved by NERC and FERC.

2. All funds from financial Penalties assessed in the United States received by the entity initiating the compliance monitoring and enforcement process shall be applied as a general offset to the entity's budget requirements for the subsequent fiscal year, if received by July 1, or for the second subsequent fiscal year, if received on or after July 1. Funds from financial Penalties shall not be directly applied to any program maintained by the entity conducting the compliance monitoring and enforcement process. Funds from financial Penalties assessed against a Canadian entity shall be applied as specified by legislation or agreement.

3. In the event that a compliance monitoring and enforcement process is conducted jointly by NERC and a Regional Entity, the Regional Entity shall receive the Penalty monies and offset the Regional Entity's budget requirements for the subsequent fiscal year.

4. Exceptions or alternatives to the foregoing provisions will be allowed if approved by NERC and by FERC or any other Applicable Governmental Authority.

1108. Special Assessments

On a demonstration of unforeseen and extraordinary circumstances requiring additional funds prior to the next funding cycle, NERC shall file with the Applicable Governmental Authorities, where authorized by applicable legislation or agreement, for authorization for an amended or supplemental budget for NERC or a Regional Entity and, if necessary under the amended or supplemental budget, to collect a special or additional assessment for statutory functions of NERC or the Regional Entity. Such filing shall include supporting materials to justify the requested funding, including any departure from the approved funding formula or method.

SECTION 1200 — REGIONAL DELEGATION AGREEMENTS

1201. Pro Forma Regional Delegation Agreement

NERC shall develop and maintain a pro forma Regional Entity delegation agreement, which shall serve as the basis for negotiation of consistent agreements for the delegation of ERO functions to Regional Entities.

1202. Regional Entity Essential Requirements

NERC shall establish the essential requirements for an entity to become qualified and maintain good standing as a Regional Entity.

1203. Negotiation of Regional Delegation Agreements

NERC shall, for all areas of North America that have provided NERC with the appropriate authority, negotiate regional delegation agreements for the purpose of ensuring all areas of the North American Bulk Power Systems are within a Regional Entity Region. In the event NERC is unable to reach agreement with Regional Entities for all areas, NERC shall provide alternative means and resources for implementing NERC functions within those areas. No delegation agreement shall take effect until it has been approved by the Applicable Governmental Authority.

1204. Conformance to Rules and Terms of Regional Delegation Agreements

NERC and each Regional Entity shall comply with all applicable ERO Rules of Procedure and the obligations stated in the regional delegation agreement.

1205. Sub-delegation

The Regional Entity shall not sub-delegate any responsibilities and authorities delegated to it by its regional delegation agreement with NERC except with the approval of NERC and FERC and other Applicable Governmental Authorities. Responsibilities and authorities may only be sub-delegated to another Regional Entity. Regional Entities may share resources with one another so long as such arrangements do not result in cross-subsidization or in any sub-delegation of authorities.

1206. Nonconformance to Rules or Terms of Regional Delegation Agreement

If a Regional Entity is unable to comply or is not in compliance with an ERO Rule of Procedure or the terms of the regional delegation agreement, the Regional Entity shall immediately notify NERC in writing, describing the area of nonconformance and the reason for not being able to conform to the Rule of Procedure. NERC shall evaluate each case and inform the affected Regional Entity of the results of the evaluation. If NERC determines that a Rule of Procedure or term of the regional delegation agreement has been violated by a Regional Entity or cannot practically be implemented by a Regional Entity, NERC shall notify the Applicable Governmental Authorities and take any actions necessary to address the situation.

1207. Regional Entity Audits

Approximately every five years and more frequently if necessary for cause, NERC shall audit each Regional Entity to verify that the Regional Entity continues to comply with NERC Rules of Procedure and the obligations of NERC delegation agreement. Audits of Regional Entities shall be conducted, to the extent practical, based on professional auditing standards recognized in the U.S., including Generally Accepted Auditing Standards, Generally Accepted Government Auditing Standards, and standards sanctioned by the Institute of Internal Auditors, and if applicable to the coverage of the audit, may be based on Canadian or other international standards. The audits required by this Section 1207 shall not duplicate the audits of Regional Entity Compliance Monitoring and Enforcement Programs provided for in **Appendix 4A**, Audit of Regional Compliance Programs, to these Rules of Procedure.

1208. Process for Considering Registered Entity Requests to Transfer to Another Regional Entity

1. A Registered Entity that is registered in the Region of one Regional Entity and believes its registration should be transferred to a different Regional Entity may submit a written request to both Regional Entities requesting that they process the proposed transfer in accordance with this section. The Registered Entity's written request shall set forth the reasons the Registered Entity believes justify the proposed transfer and shall describe any impacts of the proposed transfer on other Bulk Power System owners, operators, and users.

2. After receiving the Registered Entity's written request, the two Regional Entities shall consult with each other as to whether they agree or disagree that the requested transfer is appropriate. The Regional Entities may also consult with affected Reliability Coordinators, Balancing Authorities and Transmission Operators as appropriate. Each Regional Entity shall post the request on its website for public comment period of 21 days. In evaluating the proposed transfer, the Regional Entities shall consider the location of the Registered Entity's Bulk Power System facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators; and users, the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments to other Load-Serving Entities of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity would be transitioned from the current Regional Entity to the transferee Regional Entity; along with any other reasons for the proposed transfer stated by the Registered Entity and any other reasons either Regional Entity considers relevant. The Regional Entities may request that the Registered Entity provide additional data and information concerning the proposed transfer for the Regional Entities' use in their evaluation. The Registered Entity's current Regional Entity shall notify the Registered Entity

in writing as to whether (i) the two Regional Entities agree that the requested transfer is appropriate, (ii) the two Regional Entities agree that the requested transfer is not appropriate and should not be processed further, or (iii) the two Regional Entities disagree as to whether the proposed transfer is appropriate.

3. If the two Regional Entities agree that the requested transfer is appropriate, they shall submit a joint written request to NERC requesting that the proposed transfer be approved and that the delegation agreement between NERC and each of the Regional Entities be amended accordingly. The Regional Entities' joint written submission to NERC shall describe the reasons for the proposed transfer; the location of the Registered Entity's Bulk Power System Facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators, and users; the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity will be transitioned from the current Regional Entity to the transferee Regional Entity. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

4. If the two Regional Entities do not agree with each other that the proposed transfer is appropriate, the Regional Entity supporting the proposed transfer shall, if requested by the Registered Entity, submit a written request to NERC to approve the transfer and the related delegation agreement amendments. The Regional Entity's written request shall include the information specified in Section 1208.3. The Regional Entity that does not believe the proposed transfer is appropriate will be allowed to submit a written statement to NERC explaining why the Regional Entity believes the transfer is not appropriate and should not be approved. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

5. Prior to action by the NERC Board of Trustees on a proposed transfer of registration under Section 1208.3 or 1208.4, NERC shall post information concerning the proposed transfer, including the submissions from the Regional Entities, on its website for at least twenty-one (21) days for the purpose of receiving public comment.

6. If the NERC Board of Trustees disapproves a proposed transfer presented to it pursuant to either Section 1208.3 or 1208.4, the Regional Entity or Regional Entities that believe the transfer is appropriate may, if requested to do so by the Registered Entity, file a petition with FERC pursuant to 18 C.F.R. section 39.8(f) and (g) requesting that FERC order amendments to the delegation agreements of the two Regional Entities to effectuate the proposed transfer.

7. No transfer of a Registered Entity from one Regional Entity to another Regional Entity shall be effective (i) unless approved by FERC, and (ii) any earlier than the first day of January of the second calendar year following approval by FERC, unless an earlier effective date is agreed to by both Regional Entities and NERC and approved by FERC.

SECTION 1300 — COMMITTEES

1301. Establishing Standing Committees

The Board may from time to time create standing committees. In doing so, the Board shall approve the charter of each committee and assign specific authority to each committee necessary to conduct business within that charter. Each standing committee shall work within its Board-approved charter and shall be accountable to the Board for performance of its Board-assigned responsibilities. A NERC standing committee may not delegate its assigned work to a member forum, but, in its deliberations, may request the opinions of and consider the recommendations of a member forum.

1302. Committee Membership

Each committee shall have a defined membership composition that is explained in its charter. Committee membership may be unique to each committee, and can provide for balanced decision-making by providing for representatives from each Sector or, where Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area, by bringing together a wide diversity of opinions from industry experts with outstanding technical knowledge and experience in a particular subject area. Committee membership shall also provide the opportunity for an equitable number of members from the United States and Canada, based approximately on proportionate Net Energy for Load. All committees and other subgroups (except for those organized on other than a Sector basis because Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area) must ensure that no two stakeholder Sectors are able to control the vote on any matter, and no single Sector is able to defeat a matter. With regard to committees and subgroups pertaining to development of, interpretation of, or compliance with Reliability Standards, NERC shall provide a reasonable opportunity for membership from Sectors desiring to participate. Committees and subgroups organized on other than a Sector basis shall be reported to the NERC Board and the Member Representatives Committee, along with the reasons for constituting the committee or subgroup in the manner chosen. In such cases and subject to reasonable restrictions necessary to accomplish the mission of such committee or subgroup, NERC shall provide a reasonable opportunity for additional participation, as members or official observers, for Sectors not represented on the committee or subgroup.

1303. Procedures for Appointing Committee Members

Committee members shall be nominated and selected in a manner that is open, inclusive, and fair. Unless otherwise stated in these Rules of Procedure or approved by the Board, all committee member appointments shall be approved by the board, and committee officers shall be appointed by the Chairman of the Board.

1304. Procedures for Conduct of Committee Business

1. Notice to the public of the dates, places, and times of meetings of all committees, and all nonconfidential material provided to committee members, shall be posted on NERC's website at approximately the same time that notice is given to

committee members. Meetings of all standing committees shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance enforcement matters, litigation, or commercially sensitive or Critical Energy Infrastructure Information of any entity.

2. NERC shall maintain a set of procedures, approved by the Board, to guide the conduct of business by standing committees.

1305. Committee Subgroups

Standing committees may appoint subgroups using the same principles as in Section 1302.

SECTION 1400 — AMENDMENTS TO THE NERC RULES OF PROCEDURE

1401. Proposals for Amendment or Repeal of Rules of Procedure

In accordance with the Bylaws of NERC, requests to amend or repeal the Rules of Procedure may be submitted by (1) any fifty Members of NERC, which number shall include Members from at least three membership Sectors, (2) the Member Representatives Committee, (3) a committee of NERC to whose function and purpose the Rule of Procedure pertains, or (4) an officer of NERC.

1402. Approval of Amendment or Repeal of Rules of Procedure

Amendment to or repeal of Rules of Procedure shall be approved by the Board after public notice and opportunity for comment in accordance with the Bylaws of NERC. In approving changes to the Rules of Procedure, the Board shall consider the inputs of the Member Representatives Committee, other ERO committees affected by the particular changes to the Rules of Procedure, and other stakeholders as appropriate. After Board approval, the amendment or repeal shall be submitted to the Applicable Governmental Authorities for approval, where authorized by legislation or agreement. No amendment to or repeal of the Rules of Procedure shall be effective until it has been approved by the Applicable Governmental Authorities.

SECTION 1500 — CONFIDENTIAL INFORMATION

1501. Definitions

1. **Confidential Information** means (i) Confidential Business and Market Information; (ii) Critical Energy Infrastructure Information; (iii) personnel information that identifies or could be used to identify a specific individual, or reveals personnel, financial, medical, or other personal information; (iv) work papers, including any records produced for or created in the course of an evaluation or audit; (v) investigative files, including any records produced for or created in the course of an investigation; or (vi) Cyber Security Incident Information; provided, that public information developed or acquired by an entity shall be excluded from this definition.

2. **Confidential Business and Market Information** means any information that pertains to the interests of any entity, that was developed or acquired by that entity, and that is proprietary or competitively sensitive.

3. **Critical Energy Infrastructure Information** means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.

4. **Critical Infrastructure** means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

5. **Cyber Security Incident Information** means any information related to, describing, or which could be used to plan or cause a Cyber Security Incident.

1502. Protection of Confidential Information

1. **Identification of Confidential Information** — An owner, operator, or user of the Bulk Power System and any other party (the "Submitting Entity") shall mark as confidential any information that it submits to NERC or a Regional Entity (the "Receiving Entity") that it reasonably believes contains Confidential Information as defined by these Rules of Procedure, indicating the category or categories defined in Section 1501 in which the information falls. If the information is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the Submitting Entity shall so indicate and provide supporting references and details.

2. **Confidentiality** — Except as provided herein, a Receiving Entity shall keep in confidence and not copy, disclose, or distribute any Confidential Information or

any part thereof without the permission of the Submitting Entity, except as otherwise legally required.

3. **Information no longer Confidential –** If a Submitting Entity concludes that information for which it had sought confidential treatment no longer qualifies for that treatment, the Submitting Entity shall promptly so notify NERC or the relevant Regional Entity.

1503. Requests for Information

1. **Limitation** — A Receiving Entity shall make information available only to one with a demonstrated need for access to the information from the Receiving Entity.

2. **Form of Request** — A person with such a need may request access to information by using the following procedure:

   2.1 The request must be in writing and clearly marked "Request for Information."

   2.2 The request must identify the individual or entity that will use the information, explain the requester's need for access to the information, explain how the requester will use the information in furtherance of that need, and state whether the information is publicly available or available from another source or through another means. If the requester seeks access to information that is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the requester shall describe how it qualifies to receive such information.

   2.3 The request must stipulate that, if the requester does not seek public disclosure, the requester will maintain as confidential any information received for which a Submitting Party has made a claim of confidentiality in accordance with NERC's rules. As a condition to gaining access to such information, a requester shall execute a non-disclosure agreement in a form approved by NERC's Board of Trustees.

3. **Notice and Opportunity for Comment** — Prior to any decision to disclose information marked as confidential, the Receiving Entity shall provide written notice to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed. Failure to provide such comments or otherwise respond is not deemed waiver of the claim of confidentiality.

4. **Determination by ERO or Regional Entity** — Based on the information provided by the requester under Rule 1503.2, any comments provided by the Submitting Entity, and any other relevant available information, the chief

executive officer or his or her designee of the Receiving Entity shall determine whether to disclose such information.

5. **Appeal** — A person whose request for information is denied in whole or part may appeal that determination to the President of NERC (or the President's designee) within 30 days of the determination. Appeals filed pursuant to this Section must be in writing, addressed to the President of NERC (or the President's designee), and clearly marked "Appeal of Information Request Denial."

   NERC will provide written notice of such appeal to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed; provided that any such comments must be received within 30 days of the notice and any failure to provide such comments or otherwise respond is not deemed a waiver of the claim of confidentiality.

   The President of NERC (or the President's designee) will make a determination with respect to any appeal within 30 days. In unusual circumstances, this time limit may be extended by the President of NERC (or the President's designee), who will send written notice to the requester setting forth the reasons for the extension and the date on which a determination on the appeal is expected.

6. **Disclosure of Information** — In the event the Receiving Entity, after following the procedures herein, determines to disclose information designated as Confidential Information, it shall provide the Submitting Entity no fewer than 21 days' written notice prior to releasing the Confidential Information in order to enable such Submitting Entity to (a) seek an appropriate protective order or other remedy, (b) consult with the Receiving Entity with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Section. Should a Receiving Entity be required to disclose Confidential Information, or should the Submitting Entity waive objection to disclosure, the Receiving Entity shall furnish only that portion of the Confidential Information which the Receiving Entity's counsel advises is legally required.

7. **Posting of Determinations on Requests for Disclosure of Confidential Information** — Upon making its determination on a request for disclosure of Confidential Information, NERC or the Regional Entity, as applicable, shall (i) notify the requester that the request for disclosure is granted or denied, (ii) publicly post any determination to deny the request to disclose Confidential Information, including in such posting an explanation of the reasons for the denial (but without in such explanation disclosing the Confidential Information), and (iii) publicly post any determination that information claimed by the Submitting Entity to be Confidential Information is not Confidential Information (but without in such posting disclosing any information that has been determined to be Confidential Information).

1504. Employees, Contractors and Agents

A Receiving Entity shall ensure that its officers, trustees, directors, employees, subcontractors and subcontractors' employees, and agents to whom Confidential Information is exposed are under obligations of confidentiality that are at least as restrictive as those contained herein.

1505. Provision of Information to FERC and Other Governmental Authorities

1. **Request** — A request from FERC for reliability information with respect to owners, operators, and users of the Bulk Power System within the United States is authorized by Section 215 of the Federal Power Act. Other Applicable Governmental Authorities may have similar authorizing legislation that grants a right of access to such information. Unless otherwise directed by FERC or its staff or the other Applicable Governmental Authority requesting the information, upon receiving such a request, a Receiving Entity shall provide contemporaneous notice to the applicable Submitting Entity. In its response to such a request, a Receiving Entity shall preserve any mark of confidentiality and shall notify FERC or other Applicable Governmental Authorities that the Submitting Entity has marked the information as confidential.

2. **Continued Confidentiality** — Each Receiving Entity shall continue to treat as confidential all Confidential Information that it has submitted to NERC or to FERC or another Applicable Governmental Authority, until such time as FERC or the other Applicable Governmental Authority authorizes disclosure of such information.

1506. Permitted Disclosures

1. **Confirmed Violations** — Nothing in this Section 1500 shall prohibit the disclosure of a violation at the point when the matter is filed with an Applicable Governmental Authority as a Notice of Penalty, the "violator" admits to the violation, or the alleged violator and NERC or the Regional Entity reach a settlement regarding the violation.

2. **Compliance Information** — NERC and the Regional Entities are authorized to exchange Confidential Information related to evaluations, Compliance Audits, and Compliance Investigations in furtherance of the Compliance Monitoring and Enforcement Program, on condition they continue to maintain the confidentiality of such information.

1507. Remedies for Improper Disclosure

Any person engaged in NERC or Regional Entity activity under Section 215 of the Federal Power Act or the equivalent laws of other Applicable Governmental Authorities who improperly discloses information determined to be confidential may lose access to Confidential Information on a temporary or permanent basis and may be subject to adverse personnel action, including suspension or termination. Nothing in Section 1500

precludes an entity whose information was improperly disclosed from seeking a remedy in an appropriate court.

SECTION 1600 — REQUESTS FOR DATA OR INFORMATION

1601. Scope of a NERC or Regional Entity Request for Data or Information

Within the United States, NERC and Regional Entities may request data or information that is necessary to meet their obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Commission's regulations, 18 C.F.R. § 39.2(d). In other jurisdictions NERC and Regional Entities may request comparable data or information, using such authority as may exist pursuant to these Rules of Procedure and as may be granted by Applicable Governmental Authorities in those other jurisdictions. The provisions of Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information; the Requirements in the Reliability Standards govern. The provisions of Section 1600 shall also not apply to data or information requested in connection with a compliance or enforcement action under Section 215 of the Federal Power Act, Section 400 of these Rules of Procedure, or any procedures adopted pursuant to those authorities, in which case the Rules of Procedure applicable to the production of data or information for compliance and enforcement actions shall apply.

1602. Procedure for Authorizing a NERC Request for Data or Information

1. NERC shall provide a proposed request for data or information or a proposed modification to a previously-authorized request, including the information specified in Section 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability at least twenty-one (21) days prior to initially posting the request or modification for public comment. Submission of the proposed request or modification to the Office of Electric Reliability is for the information of the Commission. NERC is not required to receive any approval from the Commission prior to posting the proposed request or modification for public comment in accordance with Section 1602.2 or issuing the request or modification to Reporting Entities following approval by the Board of Trustees.

2. NERC shall post a proposed request for data or information or a proposed modification to a previously authorized request for data or information for a forty-five (45) day public comment period.

    2.1. A proposed request for data or information shall contain, at a minimum, the following information: (i) a description of the data or information to be requested, how the data or information will be used, and how the availability of the data or information is necessary for NERC to meet its obligations under applicable laws and agreements; (ii) a description of how the data or information will be collected and validated; (iii) a description of the entities (by functional class and jurisdiction) that will be required to provide the data or information ("Reporting Entities"); (iv) the schedule or due date for the data or information; (v) a description of any restrictions on disseminating the data or information (e.g., "Confidential Information," "Critical Energy Infrastructure Information," "aggregating"

or "identity masking"); and (vi) an estimate of the relative burden imposed on the Reporting Entities to accommodate the data or information request.

2.2. A proposed modification to a previously authorized request for data or information shall explain (i) the nature of the modifications; (ii) an estimate of the burden imposed on the Reporting Entities to accommodate the modified data or information request, and (iii) any other items from Section 1602.2.1 that require updating as a result of the modifications.

3. After the close of the comment period, NERC shall make such revisions to the proposed request for data or information as are appropriate in light of the comments. NERC shall submit the proposed request for data or information, as revised, along with the comments received, NERC's evaluation of the comments and recommendations, to the Board of Trustees.

4. In acting on the proposed request for data or information, the Board of Trustees may authorize NERC to issue it, modify it, or remand it for further consideration.

5. NERC may make minor changes to an authorized request for data or information without Board approval. However, if a Reporting Entity objects to NERC in writing to such changes within 21 days of issuance of the modified request, such changes shall require Board approval before they are implemented.

6. Authorization of a request for data or information shall be final unless, within thirty (30) days of the decision by the Board of Trustees, an affected party appeals the authorization under this Section 1600 to the Applicable Governmental Authority.

1603. Owners, Operators, and Users to Comply

Owners, operators, and users of the Bulk Power System registered on the NERC Compliance Registry shall comply with authorized requests for data and information. In the event a Reporting Entity within the United States fails to comply with an authorized request for data or information under Section 1600, NERC may request the Commission to exercise its enforcement authority to require the Reporting Entity to comply with the request for data or information and for other appropriate enforcement action by the Commission. NERC will make any request for the Commission to enforce a request for data or information through a non-public submission to the Commission's enforcement staff.

1604. Requests by Regional Entity for Data or Information

1. A Regional Entity may request that NERC seek authorization for a request for data or information to be applicable within the Region of the Regional Entity, either as a freestanding request or as part of a proposed NERC request for data or information. Any such request must be consistent with this Section 1600.

2. A Regional Entity may also develop its own procedures for requesting data or information, but any such procedures must include at least the same procedural

elements as are included in this Section 1600. Any such Regional Entity procedures or changes to such procedures shall be submitted to NERC for approval. Upon approving such procedures or changes thereto, NERC shall file the proposed procedures or proposed changes for approval by the Commission and any other Applicable Governmental Authorities applicable to the Regional Entity. The Regional Entity procedures or changes to such procedures shall not be effective in a jurisdiction until approved by, and in accordance with any revisions directed by, the Commission or other Applicable Governmental Authority.

1605. Confidentiality

If the approved data or information request includes a statement under Section 1602.1.1(v) that the requested data or information will be held confidential or treated as Critical Energy Infrastructure Information, then the applicable provisions of Section 1500 will apply without further action by a Submitting Entity. A Submitting Entity may designate any other data or information as Confidential Information pursuant to the provisions of Section 1500, and NERC or the Regional Entity shall treat that data or information in accordance with Section 1500. NERC or a Regional Entity may utilize additional protective procedures for handling particular requests for data or information as may be necessary under the circumstances.

1606. Expedited Procedures for Requesting Time-Sensitive Data or Information

1. In the event NERC or a Regional Entity must obtain data or information by a date or within a time period that does not permit adherence to the time periods specified in Section 1602, the procedures specified in Section 1606 may be used to obtain the data or information. Without limiting the circumstances in which the procedures in Section 1606 may be used, such circumstances include situations in which it is necessary to obtain the data or information (in order to evaluate a threat to the reliability or security of the Bulk Power System, or to comply with a directive in an order issued by the Commission or by another Applicable Governmental Authority) within a shorter time period than possible under Section 1602. The procedures specified in Section 1606 may only be used if authorized by the NERC Board of Trustees prior to activation of such procedures.

2. Prior to posting a proposed request for data or information, or a modification to a previously-authorized request, for public comment under Section 1606, NERC shall provide the proposed request or modification, including the information specified in paragraph 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability. The submission to the Commission's Office of Electric Reliability shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information. The submission shall be made to the Commission's Office of Electric Reliability as far in advance, up to twenty-one (21) days, of the posting of the proposed request or modification for public comments as is reasonably possible under the circumstances, but in no event less than two (2) days in advance of the public posting of the proposed request or modification.

3. NERC shall post the proposed request for data or information or proposed modification to a previously-authorized request for data or information for a public comment period that is reasonable in duration given the circumstances, but in no event shorter than five (5) days. The proposed request for data or information or proposed modification to a previously-authorized request for data or information shall include the information specified in Section 1602.2.1 or 1602.2.2, as applicable, and shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information.

4. The provisions of Sections 1602.3, 1602.4, 1602.5 and 1602.6 shall be applicable to a request for data or information or modification to a previously-authorized request for data or information developed and issued pursuant to Section 1606, except that (a) if NERC makes minor changes to an authorized request for data or information without Board approval, such changes shall require Board approval if a Reporting Entity objects to NERC in writing to such changes within five (5) days of issuance of the modified request; and (b) authorization of the request for data or information shall be final unless an affected party appeals the authorization of the request by the Board of Trustees to the Applicable Governmental Authority within five (5) days following the decision of the Board of Trustees authorizing the request, which decision shall be promptly posted on NERC's website.

SECTION 1700 — CHALLENGES TO DETERMINATIONS

1701. Scope of Authority

Section 1702 sets forth the procedures to be followed for Registered Entities to challenge determinations made by Planning Coordinators under Reliability Standard PRC-023. Section 1703 sets forth the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

1702. Challenges to Determinations by Planning Coordinators Under Reliability Standard PRC-023

1. This Section 1702 establishes the procedures to be followed when a Registered Entity wishes to challenge a determination by a Planning Coordinator of the sub-200 kV circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers (defined as "Registered Entities" for purposes of this Section 1702) must comply with the requirements of Reliability Standard PRC-023.

2. Planning Coordinator Procedures

    2.1 Each Planning Coordinator shall establish a procedure for a Registered Entity to submit a written request for an explanation of a determination made by the Planning Coordinator under PRC-023.

    2.2 A Registered Entity shall follow the procedure established by the Planning Coordinator for submitting the request for explanation and must submit any such request within 60 days of receiving the determination under PRC-023 from the Planning Coordinator.

    2.3 Within 30 days of receiving a written request from a Registered Entity, the Planning Coordinator shall provide the Registered Entity with a written explanation of the basis for its determination under PRC-023, unless the Planning Coordinator provided a written explanation of the basis for its determination when it initially informed the Registered Entity of its determination.

3. A Registered Entity may challenge the determination of the Planning Coordinator by filing with the appropriate Regional Entity, with a copy to the Planning Coordinator, within 60 days of receiving the written explanation from the Planning Coordinator. The challenge shall include the following: (a) an explanation of the technical reasons for its disagreement with the Planning Coordinator's determination, along with any supporting documentation, and (b) a copy of the Planning Coordinator's written explanation. Within 30 days of receipt of a challenge, the Planning Coordinator may file a response to the Regional Entity, with a copy to the Registered Entity.

4. The filing of a challenge in good faith shall toll the time period for compliance with PRC-023 with respect to the subject facility until such time as the challenge is withdrawn, settled or resolved.

5. The Regional Entity shall issue its written decision setting forth the basis of its determination within 90 days after it receives the challenge and send copies of the decision to the Registered Entity and the Planning Coordinator. The Regional Entity may convene a meeting of the involved entities and may request additional information. The Regional Entity shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

6. A Planning Coordinator or Registered Entity affected by the decision of the Regional Entity may, within 30 days of the decision, file an appeal with NERC, with copies to the Regional Entity and the Planning Coordinator or Registered Entity. The appeal shall state the basis of the objection to the decision of the Regional Entity and shall include the Regional Entity decision, the written explanation of the Planning Coordinator's determination under PRC-023, and the documents and reasoning filed by the Registered Entity with the Regional Entity in support of its objection. The Regional Entity, Planning Coordinator or Registered Entity may file a response to the appeal within 30 days of the appeal.

7. The Board of Trustees shall appoint a panel to decide appeals from Regional Entity decisions under Section 1702.5. The panel, which may contain alternates, shall consist of at least three appointees, one of whom must be a member of the NERC staff, who are knowledgeable about PRC-023 and transmission planning and do not have a direct financial or business interest in the outcome of the appeal. The panel shall decide the appeal within 90 days of receiving the appeal from the decision of the Regional Entity and shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

8. The Planning Coordinator or Registered Entity affected by the decision of the panel may request that the Board of Trustees review the decision by filing its request for review and a statement of reasons with NERC's Chief Reliability Officer within 30 days of the panel decision. The Board of Trustees may, in its discretion, decline to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. Within 90 days of the request for review under this Section 1702.8, the Board of Trustees may either (a) issue a decision on the merits, which shall be the final NERC decision, or (b) issue a notice declining to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. If no written decision or notice declining review is issued within 90 calendar days, the appeal shall be deemed to have been denied by the Board of Trustees and this will have the same effect as a notice declining review.

9. The Registered Entity or Planning Coordinator may appeal the final NERC decision to the Applicable Governmental Authority within 30 days of receipt of

the Board of Trustees' final decision or notice declining review, or expiration of the 90-day review period without any action by NERC.

10. The Planning Coordinator and Registered Entity are encouraged, but not required, to meet to resolve any dispute, including use of mutually agreed to alternative dispute resolution procedures, at any time during the course of the matter. In the event resolution occurs after the filing of a challenge, the Registered Entity and Planning Coordinator shall jointly provide to the applicable Regional Entity a written acknowledgement of withdrawal of the challenge or appeal, including a statement that all outstanding issues have been resolved.

1703. Challenges to NERC Determinations of BES Exception Requests Under Section 509

1. This Section 1703 establishes the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

2. A Submitting Entity (or Owner if different) aggrieved by the decision of NERC to approve or disapprove an Exception Request or to terminate an Exception with respect to any Element may, within 30 days following the date of the decision, file a written challenge to the decision with the NERC director of compliance operations, with copies to the Regional Entity and the Submitting Entity or Owner if different. The challenge shall state the basis of the objection to the decision of NERC. The Regional Entity, and the Submitting Entity or Owner if different, may file a response to the challenge within 30 days following the date the challenge is filed with NERC.

3. The challenge shall be decided by the Board of Trustees Compliance Committee. Within 90 days of the date of submission of the challenge, the Board of Trustees Compliance Committee shall issue its decision on the challenge. The decision of the Board of Trustees Compliance Committee shall be the final NERC decision; provided, that the Board of Trustees Compliance Committee may extend the deadline date for its decision to a date more than 90 days following submission of the challenge, by issuing a notice to the Submitting Entity, the Owner (if different) and the Regional Entity stating the revised deadline date and the reason for the extension.

4. The Submitting Entity, or Owner if different, may appeal the final NERC decision to, or seek review of the final NERC decision by, the Applicable Governmental Authority(ies), in accordance with the legal authority and rules and procedures of the Applicable Governmental Authority(ies). Any such appeal shall be filed within thirty (30) days following the date of the decision of the Board of Trustees Compliance Committee, or within such other time period as is provided for in the legal authority, rules or procedures of the Applicable Governmental Authority.

Attachment B
Redline version of Rules of Procedure
Sections 600 and 900

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rules of Procedure

Effective: ~~July 19, 2018~~[proposed date]

TABLE OF CONTENTS

SECTION 100 — APPLICABILITY OF RULES OF PROCEDURE 1

SECTION 200 — DEFINITIONS OF TERMS 2

SECTION 300 — RELIABILITY STANDARDS DEVELOPMENT 3

301. General 3
302. Essential Attributes for Technically Excellent Reliability Standards 3
303. Relationship between Reliability Standards and Competition 5
304. Essential Principles for the Development of Reliability Standards 5
305. Registered Ballot Body 6
306. Standards Committee 8
307. Standards Process Management 8
308. Steps in the Development of Reliability Standards 8
309. Filing of Reliability Standards for Approval by Applicable Governmental Authorities 9
310. Annual Reliability Standards Development Plan 10
311. Regional Entity Standards Development Procedures 10
312. Regional Reliability Standards 12
313. Other Regional Criteria, Guides, Procedures, Agreements, Etc. 15
314. Conflicts with Statutes, Regulations, and Orders 16
315. Revisions to NERC Standard Processes Manual 16
316. Accreditation 16
317. Periodic Review of Reliability Standards 16
318. Coordination with the North American Energy Standards Board 17
319. Archived Standards Information 17
320. Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels 17
321. Special Rule to Address Certain Regulatory Directives 18

SECTION 400 — COMPLIANCE ENFORCEMENT 22

401. Scope of the NERC Compliance Monitoring and Enforcement Program 22
402. NERC Oversight of the Regional Entity Compliance Monitoring and Enforcement Programs 25
403. Required Attributes of Regional Entity Compliance Monitoring and Enforcement Programs . 29
404. NERC Monitoring of Compliance for Regional Entities or Bulk Power Owners, Operator, or Users 37
405. Monitoring of Reliability Standards and Other Requirements Applicable to NERC 38
406. Independent Audits of the NERC Compliance Monitoring and Enforcement Program 39
407. Penalties, Sanctions, and Remedial Action Directives 39
408. Review of NERC Decisions 40
409. Appeals from Final Decisions of Hearing Bodies 41
410. Hold Harmless 42
411. Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards 43
412. Certification of Questions from Hearing Bodies for Decision by the NERC Board of Trustees Compliance Committee 43
413. Review and Processing of Hearing Body Final Decisions that Are Not Appealed 44
414. Appeals of Decisions of Hearing Bodies Granting or Denying Motions to Intervene in Hearing Body Proceedings 44

SECTION 500 — ORGANIZATION REGISTRATION AND CERTIFICATION 46

501. Scope of the Organization Registration and Organization Certification Programs 46
502. Organization Registration and Organization Certification Program Requirements 50
503. Regional Entity Implementation of Organization Registration and Organization Certification Program Requirements 52
504. Appeals 53
505. Program Maintenance 53
506. Independent Audit of NERC Organization Registration and Organization Certification Program 53
507. Provisions Relating to Joint Registration Organizations (JRO) 54
508. Provisions Relating to Coordinated Functional Registration (CFR) Entities 55
509. Exceptions to the Definition of the Bulk Electric System 56

SECTION 600 — PERSONNEL CERTIFICATION PROGRAM 57

601. Scope of Personnel Certification Program 57
602. Structure of ERO Personnel Certification Program 57
603. Examination and Maintenance of NERC System Operator Certification Credentials 57
604. Dispute Resolution Process 58
605. Disciplinary Action 60
606. Candidate Testing 62
607. Public Information About the Personnel Certification Program 62
608. Responsibilities to Applicants for Certification or Re-Certification 62
609. Responsibilities to Employers of Certified Personnel 62

SECTION 700 — RELIABILITY READINESS EVALUATION AND IMPROVEMENT AND FORMATION OF SECTOR FORUMS 64

701. Confidentiality Requirements for Readiness Evaluations and Evaluation Team Members 64
702. Formation of Sector Forum 64

SECTION 800 — RELIABILITY ASSESSMENT AND PERFORMANCE ANALYSIS 65

801. Objectives of the Reliability Assessment and Performance Analysis Program 65
802. Scope of the Reliability Assessment Program 65
803. Reliability Assessment Reports 66
804. Reliability Assessment Data and Information Requirements 67
805. Reliability Assessment Process 68
806. Scope of the Reliability Performance and Analysis Program 70
807. Analysis of Major Events 70
808. Analysis of Off-Normal Occurrences, Bulk Power System Performance, and Bulk Power System Vulnerabilities 71
809. Reliability Benchmarking 72
810. Information Exchange and Issuance of NERC Advisories, Recommendations and Essential Actions 72
811. Equipment Performance Data 73

SECTION 900 — TRAINING AND EDUCATION 74

901. Scope of the Training and Education Program 74
902. Continuing Education Program 74

SECTION 1000 — SITUATION AWARENESS AND INFRASTRUCTURE SECURITY 75

1001. Situation Awareness 75
1002. Reliability Support Services 75

1003. Infrastructure Security Program 76

SECTION 1100 — ANNUAL NERC BUSINESS PLANS AND BUDGETS 78

1101. Scope of Business Plans and Budgets 78
1102. NERC Funding and Cost Allocation 78
1103. NERC Budget Development 78
1104. Submittal of Regional Entity Budgets to NERC 79
1105. Submittal of NERC and Regional Entity Budgets to Governmental Authorities for Approval 79
1106. NERC and Regional Entity Billing and Collections 80
1107. Penalty Applications 81
1108. Special Assessments 82

SECTION 1200 — REGIONAL DELEGATION AGREEMENTS 83

1201. Pro Forma Regional Delegation Agreement 83
1202. Regional Entity Essential Requirements 83
1203. Negotiation of Regional Delegation Agreements 83
1204. Conformance to Rules and Terms of Regional Delegation Agreements 83
1205. Sub-delegation 83
1206. Nonconformance to Rules or Terms of Regional Delegation Agreement 83
1207. Regional Entity Audits 84
1208. Process for Considering Registered Entity Requests to Transfer to Another Regional Entity .. 84

SECTION 1300 — COMMITTEES 87

1301. Establishing Standing Committees 87
1302. Committee Membership 87
1303. Procedures for Appointing Committee Members 87
1304. Procedures for Conduct of Committee Business 87
1305. Committee Subgroups 88

SECTION 1400 — AMENDMENTS TO THE NERC RULES OF PROCEDURE 89

1401. Proposals for Amendment or Repeal of Rules of Procedure 89
1402. Approval of Amendment or Repeal of Rules of Procedure 89

SECTION 1500 — CONFIDENTIAL INFORMATION 90

1501. Definitions 90
1502. Protection of Confidential Information 90
1503. Requests for Information 91
1504. Employees, Contractors and Agents 93
1505. Provision of Information to FERC and Other Governmental Authorities 93
1506. Permitted Disclosures 93
1507. Remedies for Improper Disclosure 93

SECTION 1600 — REQUESTS FOR DATA OR INFORMATION 95

1601. Scope of a NERC or Regional Entity Request for Data or Information 95
1602. Procedure for Authorizing a NERC Request for Data or Information 95
1603. Owners, Operators, and Users to Comply 96
1604. Requests by Regional Entity for Data or Information 96
1605. Confidentiality 97
1606. Expedited Procedures for Requesting Time-Sensitive Data or Information 97

SECTION 1700 — CHALLENGES TO DETERMINATIONS 99

1701. Scope of Authority 99
1702. Challenges to Determinations by Planning Coordinators Under Reliability Standard PRC-023 99
1703. Challenges to NERC Determinations of BES Exception Requests Under Section 509 101

SECTION 100 — APPLICABILITY OF RULES OF PROCEDURE

NERC and NERC Members shall comply with these Rules of Procedure. Each Regional Entity shall comply with these Rules of Procedure as applicable to functions delegated to the Regional Entity by NERC or as required by an Applicable Governmental Authority or as otherwise provided.

Each Bulk Power System owner, operator, and user shall comply with all Rules of Procedure of NERC that are made applicable to such entities by approval pursuant to applicable legislation or regulation, or pursuant to agreement.

Any entity that is unable to comply or that is not in compliance with a NERC Rule of Procedure shall immediately notify NERC in writing, stating the Rule of Procedure of concern and the reason for not being able to comply with the Rule of Procedure.

NERC shall evaluate each case and inform the entity of the results of the evaluation. If NERC determines that a Rule of Procedure has been violated, or cannot practically be complied with, NERC shall notify the Applicable Governmental Authorities and take such other actions as NERC deems appropriate to address the situation.

NERC shall comply with each approved Reliability Standard that identifies NERC or the Electric Reliability Organization as a responsible entity. Regional Entities shall comply with each approved Reliability Standard that identifies Regional Entities as responsible entities. A violation by NERC or a Regional Entity of such a Reliability Standard shall constitute a violation of these Rules of Procedure.

SECTION 200 — DEFINITIONS OF TERMS

Definitions of terms used in the NERC Rules of Procedure are set forth in **Appendix 2**, *Definitions Used in the Rules of Procedure*.

SECTION 300 — RELIABILITY STANDARDS DEVELOPMENT

301. General

NERC shall develop and maintain Reliability Standards that apply to Bulk Power System owners, operators, and users and that enable NERC and Regional Entities to measure the reliability performance of Bulk Power System owners, operators, and users; and to hold them accountable for Reliable Operation of the Bulk Power Systems. The Reliability Standards shall be technically excellent, timely, just, reasonable, not unduly discriminatory or preferential, in the public interest, and consistent with other applicable standards of governmental authorities.

302. Essential Attributes for Technically Excellent Reliability Standards

1. **Applicability** — Each Reliability Standard shall clearly identify the functional classes of entities responsible for complying with the Reliability Standard, with any specific additions or exceptions noted. Such functional classes[1] include: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, market operators, Planning Authorities, Transmission Planners, Resource Planners, and Distribution Providers. Each Reliability Standard shall also identify the geographic applicability of the Reliability Standard, such as the entire North American Bulk Power System, an Interconnection, or within a Region. A Reliability Standard may also identify any limitations on the applicability of the Reliability Standard based on electric Facility characteristics.

2. **Reliability Objectives** — Each Reliability Standard shall have a clear statement of purpose that shall describe how the Reliability Standard contributes to the reliability of the Bulk Power System. The following general objectives for the Bulk Power System provide a foundation for determining the specific objective(s) of each Reliability Standard:

    2.1 **Reliability Planning and Operating Performance** — Bulk Power Systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.

    2.2 **Frequency and Voltage Performance** — The frequency and voltage of Bulk Power Systems shall be controlled within defined limits through the balancing of Real and Reactive Power supply and demand.

[1] These functional classes of entities are derived from NERC's Reliability Functional Model. When a Reliability Standard identifies a class of entities to which it applies, that class must be defined in the Glossary of Terms Used in NERC Reliability Standards.

2.3 **Reliability Information** — Information necessary for the planning and operation of reliable Bulk Power Systems shall be made available to those entities responsible for planning and operating Bulk Power Systems.

2.4 **Emergency Preparation** — Plans for emergency operation and system restoration of Bulk Power Systems shall be developed, coordinated, maintained, and implemented.

2.5 **Communications and Control** — Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of Bulk Power Systems.

2.6 **Personnel** — Personnel responsible for planning and operating Bulk Power Systems shall be trained and qualified, and shall have the responsibility and authority to implement actions.

2.7 **Wide-Area View** — The reliability of the Bulk Power Systems shall be assessed, monitored, and maintained on a Wide-Area basis.

2.8 **Security** — Bulk Power Systems shall be protected from malicious physical or cyber attacks.

3. **Performance Requirement or Outcome** — Each Reliability Standard shall state one or more performance Requirements, which if achieved by the applicable entities, will provide for a reliable Bulk Power System, consistent with good utility practices and the public interest. Each Requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for Bulk Power System reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability** — Each performance Requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that Requirement. Each performance Requirement shall have one or more associated measures used to objectively evaluate compliance with the Requirement. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance.

5. **Technical Basis in Engineering and Operations** — Each Reliability Standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.

6. **Completeness** — Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance.

7. **Consequences for Noncompliance** — In combination with guidelines for Penalties and sanctions, as well as other ERO and Regional Entity compliance

documents, the consequences of violating a Reliability Standard are clearly presented to the entities responsible for complying with the Reliability Standards.

8. **Clear Language** — Each Reliability Standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance.

9. **Practicality** — Each Reliability Standard shall establish Requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

10. **Consistent Terminology** — To the extent possible, Reliability Standards shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards development process.

303. Relationship between Reliability Standards and Competition

To ensure Reliability Standards are developed with due consideration of impacts on competition, to ensure Reliability Standards are not unduly discriminatory or preferential, and recognizing that reliability is an essential requirement of a robust North American economy, each Reliability Standard shall meet all of these market-related objectives:

1. **Competition** — A Reliability Standard shall not give any market participant an unfair competitive advantage.

2. **Market Structures** — A Reliability Standard shall neither mandate nor prohibit any specific market structure.

3. **Market Solutions** — A Reliability Standard shall not preclude market solutions to achieving compliance with that Reliability Standard.

4. **Commercially Sensitive Information** — A Reliability Standard shall not require the public disclosure of commercially sensitive information or other Confidential Information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with Reliability Standards.

5. **Adequacy** — NERC shall not set Reliability Standards defining an adequate amount of, or requiring expansion of, Bulk Power System resources or delivery capability.

304. Essential Principles for the Development of Reliability Standards

NERC shall develop Reliability Standards in accordance with the NERC *Standard Processes Manual*, which is incorporated into these Rules of Procedure as **Appendix 3A**. Appeals in connection with the development of a Reliability Standard shall also be conducted in accordance with the NERC *Standard Processes Manual*. Any amendments

or revisions to the *Standard Processes Manual* shall be consistent with the following essential principles:

1. **Openness** — Participation shall be open to all Persons and who are directly and materially affected by the reliability of the North American Bulk Power System. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in NERC or any other organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

2. **Transparency** — The process shall be transparent to the public.

3. **Consensus-building** —The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

4. **Fair Balance of Interests** — The process shall fairly balance interests of all stakeholders and shall not be dominated by any two Segments as defined in **Appendix 3D**, *Development of the Registered Ballot Body*, of these Rules of Procedure, and no single Segment, individual or organization shall be able to defeat a matter.

5. **Due Process** — Development of Reliability Standards shall provide reasonable notice and opportunity for any Person with a direct and material interest to express views on a proposed Reliability Standard and the basis for those views, and to have that position considered in the development of the Reliability Standards.

6. **Timeliness** — Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

305. Registered Ballot Body

NERC Reliability Standards shall be approved by a Registered Ballot Body prior to submittal to the Board and then to Applicable Governmental Authorities for their approval, where authorized by applicable legislation or agreement. This Section 305 sets forth the rules pertaining to the composition of, and eligibility to participate in, the Registered Ballot Body.

1. **Eligibility to Vote on Reliability Standards** — Any person or entity may join the Registered Ballot Body to vote on Reliability Standards, whether or not such person or entity is a Member of NERC.

2. **Inclusive Participation** — The Segment qualification guidelines are inclusive; i.e., any entity with a legitimate interest in the reliability of the Bulk Power

System that can meet any one of the eligibility criteria for a Segment is entitled to belong to and vote in each Segment for which it qualifies, subject to limitations defined in Sections 305.3 and 305.5.

3. **General Criteria for Registered Ballot Body Membership** — The general criteria for membership in the Segments are:

   3.1 **Multiple Segments** — A corporation or other organization with integrated operations or with affiliates that qualifies to belong to more than one Segment (e.g., Transmission Owners and Load-Serving Entities) may join once in each Segment for which it qualifies, provided that each Segment constitutes a separate membership and the organization is represented in each Segment by a different representative. Affiliated entities are collectively limited to one membership in each Segment for which they are qualified.

   3.2 **Withdrawing from a Segment or Changing Segments** — After its initial registration in a Segment, each registered participant may elect to withdraw from a Segment or apply to change Segments at any time.

   3.3 **Review of Segment Criteria** — The Board shall review the qualification guidelines and rules for joining Segments at least every three years to ensure that the process continues to be fair, open, balanced, and inclusive. Public input will be solicited in the review of these guidelines.

4. **Proxies for Voting on Reliability Standards** — Any registered participant may designate an agent or proxy to vote on its behalf. There are no limits on how many proxies an agent may hold. However, for the proxy to be valid, NERC must have in its possession written documentation signed by the representative of the registered participant that the voting right by proxy has been transferred from the registered participant to the agent.

5. **Segments** — The specific criteria for membership in each Registered Ballot Body Segment are defined in the *Development of the Registered Ballot Body* in **Appendix 3D.**

6. **Review of Segment Entries** — NERC shall review all applications for joining the Registered Ballot Body, and shall make a determination of whether the applicant's self-selection of a Segment satisfies at least one of the guidelines to belong to that Segment. The entity shall then become eligible to participate as a voting member of that Segment. The Standards Committee shall resolve disputes regarding eligibility for membership in a Segment, with the applicant having the right of appeal to the Board.

306. Standards Committee

The Standards Committee shall provide oversight of the Reliability Standards development process to ensure stakeholder interests are fairly represented. The Standards Committee shall not under any circumstance change the substance of a draft or approved Reliability Standard.

1. **Membership** — The Standards Committee is a representative committee comprising representatives of two members of each of the Segments in the Registered Ballot Body and two officers elected to represent the interests of the industry as a whole.

2. **Elections** — Standards Committee members are elected for staggered (one per Segment per year) two-year terms by the respective Segments in accordance with the *Procedure for the Election of Members of the NERC Standards Committee*, which is incorporated into these Rules of Procedure as **Appendix 3B**. Segments may use their own election procedure if such a procedure is ratified by two-thirds of the members of a Segment and approved by the Board.

3. **Canadian Representation**

   The Standards Committee will include Canadian representation as provided in **Appendix 3B**, *Procedure for the Election of Members of the NERC Standards Committee*.

4. **Open Meetings** — All meetings of the Standards Committee shall be open and publicly noticed on the NERC website.

307. Standards Process Management

NERC shall assign a standards process manager to administer the development of continent-wide Reliability Standards and a regional standards manager to administer the development of Regional Reliability Standards. The standards process manager shall be responsible for ensuring that the development and revision of Reliability Standards are in accordance with the NERC *Standard Processes Manual*. The standards process manager and the regional standards manager shall work to achieve the highest degree of integrity and consistency of quality and completeness of the Reliability Standards. The regional standards manager shall coordinate with any Regional Entities that develop Regional Reliability Standards to ensure those Regional Reliability Standards are effectively integrated with the NERC Reliability Standards.

308. Steps in the Development of Reliability Standards

1. **Procedure** — NERC shall develop Reliability Standards through the process set forth in the NERC *Standard Processes Manual* (**Appendix 3A**). The *Standard Processes Manual* includes provisions for developing Reliability Standards that can be completed using expedited processes, including a process to develop Reliability Standards to address national security situations that involve confidential issues.

2. **Board Adoption** — Reliability Standards or revisions to Reliability Standards approved by the ballot pool in accordance with the *Standard Processes Manual* shall be submitted for adoption by the Board. No Reliability Standard or revision to a Reliability Standard shall be effective unless adopted by the Board.

3. **Governmental Approval** — After Board adoption, a Reliability Standard or revision to a Reliability Standard shall be submitted to all Applicable Governmental Authorities in accordance with Section 309. No Reliability Standard or revision to a Reliability Standard shall be effective within a geographic area over which an Applicable Governmental Authority has jurisdiction unless it is approved by such Applicable Governmental Authority or is otherwise made effective pursuant to the laws applicable to such Applicable Governmental Authority.

309. Filing of Reliability Standards for Approval by Applicable Governmental Authorities

1. **Filing of Reliability Standards for Approval** — Where authorized by applicable legislation or agreement, NERC shall file with the Applicable Governmental Authorities each Reliability Standard, modification to a Reliability Standard, or withdrawal of a Reliability Standard that is adopted by the Board. Each filing shall be in the format required by the Applicable Governmental Authority and shall include: a concise statement of the basis and purpose of the Reliability Standard; the text of the Reliability Standard; the implementation plan for the Reliability Standard; a demonstration that the Reliability Standard meets the essential attributes of Reliability Standards as stated in Section 302; the drafting team roster; the ballot pool and final ballot results; and a discussion of public comments received during the development of the Reliability Standard and the consideration of those comments.

2. **Remanded Reliability Standards and Directives to Develop Standards** — If an Applicable Governmental Authority remands a Reliability Standard to NERC or directs NERC to develop a Reliability Standard, NERC shall within five (5) business days notify all other Applicable Governmental Authorities, and shall within thirty (30) calendar days report to all Applicable Governmental Authorities a plan and timetable for modification or development of the Reliability Standard. Reliability Standards that are remanded or directed by an Applicable Governmental Authority shall be modified or developed using the *Standard Processes Manual*. NERC shall, during the development of a modification for the remanded Reliability Standard or directed Reliability Standard, consult with other Applicable Governmental Authorities to coordinate any impacts of the proposed Reliability Standards in those other jurisdictions. The expedited standards development process may be applied if necessary to meet a timetable for action required by the Applicable Governmental Authorities, respecting to the extent possible the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interest in developing Reliability Standards. If the Board of

Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply.

3. **Directives to Develop Reliability Standards under Extraordinary Circumstances** — An Applicable Governmental Authority may, on its own initiative, determine that extraordinary circumstances exist requiring expedited development of a Reliability Standard. In such a case, the Applicable Governmental Authority may direct the development of a Reliability Standard within a certain deadline. NERC staff shall prepare the Standards Authorization Request. The proposed Reliability Standard will then proceed through the Reliability Standards development process, using the expedited action process described in the *Standard Processes Manual* as necessary to meet the specified deadline. The timeline will be developed to respect, to the extent possible, the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards. If the Board of Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply, with appropriate modification of the timeline.

310. Annual Reliability Standards Development Plan

NERC shall develop and provide an annual Reliability Standards Development Plan for development of Reliability Standards to the Applicable Governmental Authorities. NERC shall consider the comments and priorities of the Applicable Governmental Authorities in developing and updating the annual Reliability Standards Development Plan. Each annual Reliability Standards Development Plan shall include a progress report comparing results achieved to the prior year's Reliability Standards Development Plan.

311. Regional Entity Standards Development Procedures

1. **NERC Approval of Regional Entity Reliability Standards Development Procedure** — To enable a Regional Entity to develop Regional Reliability Standards that are to be recognized and made part of NERC Reliability Standards, a Regional Entity may request NERC to approve a Regional Reliability Standards development procedure.

2. **Public Notice and Comment on Regional Reliability Standards Development Procedure** — Upon receipt of such a request, NERC shall publicly notice and request comment on the proposed Regional Reliability Standards development procedure, allowing a minimum of 45 days for comment. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to withdraw the request, revise the Regional Reliability Standards development procedure and request another posting for comment, or submit the

Regional Reliability Standards development procedure, along with its consideration of any objections received, for approval by NERC.

3. **Evaluation of Regional Reliability Standards Development Procedure** — NERC shall evaluate whether a Regional Reliability Standards development procedure meets the criteria listed below and shall consider stakeholder comments, any unresolved stakeholder objections, and the consideration of comments provided by the Regional Entity, in making that determination. If NERC determines the Regional Reliability Standards development procedure meets these requirements, the Regional Reliability Standards development procedure shall be submitted to the Board for approval. The Board shall consider the recommended action, stakeholder comments, any unresolved stakeholder comments, and the Regional Entity consideration of comments in determining whether to approve the Regional Reliability Standards development procedure.

3.1 **Evaluation Criteria** — The Regional Reliability Standards development procedure shall be:

3.1.1 **Open** — The Regional Reliability Standards development procedure shall provide that any person or entity who is directly and materially affected by the reliability of the Bulk Power Systems within the Regional Entity shall be able to participate in the development and approval of Reliability Standards. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in the Regional Entity, a Regional Entity or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

3.1.2 **Inclusive** — The Regional Reliability Standards development procedure shall provide that any Person with a direct and material interest has a right to participate by expressing an opinion and its basis, having that position considered, and appealing through an established appeals process if adversely affected.

3.1.3 **Balanced** — The Regional Reliability Standards development procedure shall have a balance of interests and shall not permit any two interest categories to dominate a matter or any single interest category to defeat a matter.

3.1.4 **Due Process** — The Regional Reliability Standards development procedure shall provide for reasonable notice and opportunity for public comment. At a minimum, the Regional Reliability Standards development procedure shall include public notice of the intent to develop a Regional Reliability Standard, a public comment period on the proposed Regional Reliability Standard,

due consideration of those public comments, and a ballot of interested stakeholders.

3.1.5 **Transparent** — All actions material to the development of Regional Reliability Standards shall be transparent. All Regional Reliability Standards development meetings shall be open and publicly noticed on the Regional Entity's website.

3.1.6 **Accreditation of Regional Standards Development Procedure** — A Regional Entity's Regional Reliability Standards development procedure that is accredited by the American National Standards Institute shall be deemed to meet the criteria listed in this Section 311.3.1, although such accreditation is not a prerequisite for approval by NERC.

3.1.7 **Use of NERC Procedure** — A Regional Entity may adopt the NERC *Standard Processes Manual* as the Regional Reliability Standards development procedure, in which case the Regional Entity's Regional Reliability Standards development procedure shall be deemed to meet the criteria listed in this Section 311.3.1.

4. **Revisions of Regional Reliability Standards Development Procedures** — Any revision to a Regional Reliability Standards development procedure shall be subject to the same approval requirements set forth in Sections 311.1 through 311.3.

5. **Duration of Regional Reliability Standards Development Procedures** — The Regional Reliability Standards development procedure shall remain in effect until such time as it is replaced with a new version approved by NERC or it is withdrawn by the Regional Entity. The Regional Entity may, at its discretion, withdraw its Regional Reliability Standards development procedure at any time.

312. Regional Reliability Standards

1. **Basis for Regional Reliability Standards** — 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. Such Regional Reliability Standards shall in all cases be submitted to NERC for adoption and, if adopted, made part of the NERC Reliability Standards and shall be enforceable in accordance with the delegation agreement between NERC and the Regional Entity or other instrument granting authority over enforcement to the Regional Entity. No entities other than NERC and the Regional Entity shall be permitted to develop Regional Reliability Standards that are enforceable under statutory authority delegated to NERC and the Regional Entity.

2. **Regional Reliability Standards That are Directed by a NERC Reliability Standard** — Although it is the intent of NERC to promote uniform Reliability

Standards across North America, in some cases it may not be feasible to achieve a reliability objective with a Reliability Standard that is uniformly applicable across North America. In such cases, NERC may direct Regional Entities to develop Regional Reliability Standards necessary to implement a NERC Reliability Standard. Such Regional Reliability Standards that are developed pursuant to a direction by NERC shall be made part of the NERC Reliability Standards.

3. **Procedure for Developing an Interconnection-wide Regional Standard** — A Regional Entity organized on an Interconnection-wide basis may propose a Regional Reliability Standard for approval as a NERC Reliability Standard to be made mandatory for all applicable Bulk Power System owners, operators, and users within that Interconnection.

   3.1 **Presumption of Validity** — An Interconnection-wide Regional Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities, shall be adopted as a NERC Reliability Standard. NERC shall rebuttably presume that a Regional Reliability Standard developed, in accordance with a Regional Reliability Standards development process approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities.

   3.2 **Notice and Comment Procedure for Interconnection-wide Regional Reliability Standard** — NERC shall publicly notice and request comment on the proposed Interconnection-wide Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to comment on or withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for approval by NERC.

   3.3 **Adoption of Interconnection-wide Regional Reliability Standard by NERC** — NERC shall evaluate and recommend whether a proposed Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections that could serve as a basis for rebutting the presumption of validity of the Regional Reliability Standard. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning the proposed Regional Reliability Standard, shall have the option of

presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, NERC's recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

3.4 **Applicable Governmental Authority Approval** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

3.5 **Enforcement of Interconnection-wide Regional Reliability Standard** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

4. **Procedure for Developing Non-Interconnection-Wide Regional Reliability Standards** — Regional Entities that are not organized on an Interconnection-wide basis may propose Regional Reliability Standards to apply within their respective Regions. Such Regional Reliability Standards may be developed through the NERC Reliability Standards development procedure, or alternatively, through a Regional Reliability Standards development procedure that has been approved by NERC.

4.1 **No Presumption of Validity** — Regional Reliability Standards that are not proposed to be applied on an Interconnection-wide basis are not presumed to be valid but may be demonstrated by the proponent to be valid.

4.2 **Notice and Comment Procedure for Non-Interconnection-wide Regional Reliability Standards** — NERC shall publicly notice and request comment on the proposed Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to comment on or resolve any objections identified in the comments and may choose to withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for adoption by NERC.

4.3 **NERC Adoption of Non-Interconnection-wide Regional Reliability Standards** — NERC shall evaluate and recommend whether a proposed non-Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, the recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

4.4 **Applicable Governmental Authority Approval** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

4.5 **Enforcement of Non-Interconnection-wide Regional Reliability Standards** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

5. **Appeals** — A Regional Entity shall have the right to appeal NERC's decision not to adopt a proposed Regional Reliability Standard or Variance to the Commission or other Applicable Governmental Authority.

313. Other Regional Criteria, Guides, Procedures, Agreements, Etc.

1. **Regional Criteria** — 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. Regional Criteria may include specific acceptable 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 authority delegated by NERC pursuant to delegation agreements and do not require NERC approval.

2. **Catalog of Regional Criteria** — NERC shall maintain a current catalog of Regional Criteria. Regional Entities shall provide a catalog listing of Regional Criteria to NERC and shall notify NERC of changes to the listing. Regional Entities shall provide any listed document to NERC upon written request.

314. Conflicts with Statutes, Regulations, and Orders

Notice of Potential Conflict — If a Bulk Power System owner, operator, or user determines that a NERC or Regional Reliability Standard may conflict with a function, rule, order, tariff, rate schedule, legislative requirement or agreement that has been accepted, approved, or ordered by a governmental authority affecting that entity, the entity shall expeditiously notify the governmental authority, NERC, and the relevant Regional Entity of the conflict.

1. **Determination of Conflict —** NERC, upon request of the governmental authority, may advise the governmental authority regarding the conflict and propose a resolution of the conflict, including revision of the Reliability Standard if appropriate.

2. **Regulatory Precedence** — Unless otherwise ordered by a governmental authority, the affected Bulk Power System owner, operator, or user shall continue to follow the function, rule, order, tariff, rate schedule, legislative requirement, or agreement accepted, approved, or ordered by the governmental authority until the governmental authority finds that a conflict exists and orders a remedy and such remedy is affected.

315. Revisions to NERC Standard Processes Manual

Any person or entity may submit a written request to modify NERC *Standard Processes Manual*. Consideration of the request and development of the revision shall follow the process defined in the NERC *Standard Processes Manual*. Upon approval by the Board, the revision shall be submitted to the Applicable Governmental Authorities for approval. Changes shall become effective only upon approval by the Applicable Governmental Authorities or on a date designated by the Applicable Governmental Authorities or as otherwise applicable in a particular jurisdiction.

316. Accreditation

NERC shall seek and maintain accreditation of the NERC Reliability Standards development process by the American National Standards Institute.

317. Periodic Review of Reliability Standards

NERC shall complete a periodic review of each NERC Reliability Standard in accordance with the NERC *Standard Processes Manual*. The standards process manager shall be responsible for administration of the periodic review of Reliability Standards. As a result of this review, the NERC Reliability Standard shall be reaffirmed, revised, or withdrawn. If the review indicates a need to revise or withdraw the Reliability Standard, a request for revision or withdrawal shall be prepared, submitted and addressed in accordance with the NERC *Standard Processes Manual*.

318. Coordination with the North American Energy Standards Board

NERC shall maintain a close working relationship with the North American Energy Standards Board and ISO/RTO Council to ensure effective coordination of wholesale electric business practice standards and market protocols with the NERC Reliability Standards.

319. Archived Standards Information

NERC shall maintain a historical record of Reliability Standards information that is no longer maintained on-line. For example, Reliability Standards that have been retired may be removed from the on-line system. Archived information shall be retained indefinitely as practical, but in no case less than six years or one complete Reliability Standards review cycle from the date on which the Reliability Standard was no longer in effect. Archived records of Reliability Standards information shall be available electronically within 30 days following the receipt by the NERC standards information manager of a written request.

320. Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels

1. **Development of Violation Risk Factors and Violation Severity Levels** — NERC shall follow the process for developing Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) as set forth in the Standard Processes Manual, Appendix 3A to these Rules of Procedure.

2. **Remands of Directed Revision of VRFs and VSLs by Applicable Governmental Authorities** — If an Applicable Governmental Authority remands or directs a revision to a Board-approved VRF or VSL assignment, the NERC director of standards, after consulting with the standard drafting team, Standards Committee, and the NERC director of compliance operations, will recommend to the Board one of the following actions: (1) filing a request for clarification; (2) filing for rehearing or for review of the Applicable Governmental Authority decision; or (3) approval of the directed revisions to the VRF or VSL. If and to the extent time is available prior to the deadline for the Board's decision, an opportunity for interested parties to comment on the action taken will be provided.

3. **Alternative Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels** — In the event the Reliability Standards development process fails to produce Violation Risk Factors or Violation Severity Levels for a particular Reliability Standard in a timely manner, the Board of Trustees may approve Violation Risk Factors or Violation Severity Levels for that Reliability Standard after notice and opportunity for comment. In approving VRFs and VSLs, the Board shall consider the inputs of the Member Representatives Committee, affected stakeholders and NERC staff.

321. Special Rule to Address Certain Regulatory Directives

In circumstances where this Rule 321 applies, the Board of Trustees shall have the authority to take one or more of the actions set out below. The Board of Trustees shall have the authority to choose which one or more of the actions are appropriate to the circumstances and need not take these actions in sequential steps.

1. The Standards Committee shall have the responsibility to ensure that standards drafting teams address specific matters that are identified in directives issued by Applicable Governmental Authorities. If the Board of Trustees is presented with a proposed Reliability Standard that fails to address such directives, the Board of Trustees has the authority to remand, with instructions (including establishing a timetable for action), the proposed Reliability Standard to the Standards Committee.

2. Upon a written finding by the Board of Trustees that a ballot pool has failed to approve a proposed Reliability Standard that contains a provision to address a specific matter identified in a directive issued by an Applicable Governmental Authority, the Board of Trustees has the authority to remand the proposed Reliability Standard to the Standards Committee, with instructions to (i) convene a public technical conference to discuss the issues surrounding the regulatory directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified; (ii) working with NERC staff, prepare a memorandum discussing the issues, an analysis of the alternatives considered and other appropriate matters; and (iii) re-ballot the proposed Reliability Standard one additional time, with such adjustments in the schedule as are necessary to meet the deadline contained in paragraph 2.1 of this Rule.

   2.1 Such a re-ballot shall be completed within forty-five (45) days of the remand. The Standards Committee memorandum shall be included in the materials made available to the ballot pool in connection with the re-ballot.

   2.2 In any such re-ballot, negative votes without comments related to the proposal shall be counted for purposes of establishing a quorum, but only affirmative votes and negative votes with comments related to the proposal shall be counted for purposes of determining the number of votes cast and whether the proposed Reliability Standard has been approved.

3. If the re-balloted proposed Reliability Standard achieves at least an affirmative two-thirds majority vote of the weighted Segment votes cast, with a quorum established, then the proposed Reliability Standard shall be deemed approved by the ballot pool and shall be considered by the Board of Trustees for approval.

4. If the re-balloted proposed Reliability Standard fails to achieve at least an affirmative two-thirds majority vote of the weighted Segment votes cast, but does

achieve at least a sixty percent affirmative majority of the weighted Segment votes cast, with a quorum established, then the Board of Trustees has the authority to consider the proposed Reliability Standard for approval under the following procedures:

4.1 The Board of Trustees shall issue notice of its intent to consider the proposed Reliability Standard and shall solicit written public comment particularly focused on the technical aspects of the provisions of the proposed Reliability Standard that address the specific matter identified in the regulatory directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified.

4.2 The Board of Trustees may, in its discretion, convene a public technical conference to receive additional input on the matter.

4.3 After considering the developmental record, the comments received during balloting and the additional input received under paragraphs 4.1 and 4.2 of this Rule, the Board of Trustees has authority to act on the proposed Reliability Standard.

4.3.1 If the Board of Trustees finds that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to approve the proposed Reliability Standard and direct that it be filed with Applicable Governmental Authorities with a request that it be made effective.

4.3.2 If the Board of Trustees is unable to find that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to treat the proposed Reliability Standard as a draft Reliability Standard and direct that the draft Reliability Standard and complete developmental record, including the additional input received under paragraphs 4.1 and 4.2 of this Rule, be filed with the Applicable Governmental Authorities as a compliance filing in response to the order giving rise to the regulatory directive, along with a recommendation that the Reliability Standard not be made effective and an explanation of the basis for the recommendation.

5. Upon a written finding by the Board of Trustees that standard drafting team has failed to develop, or a ballot pool has failed to approve, a proposed Reliability

Standard that contains a provision to address a specific matter identified in a directive issued by an Applicable Governmental Authority, the Board of Trustees has the authority to direct the Standards Committee (with the assistance of stakeholders and NERC staff) to prepare a draft Reliability Standard that addresses the regulatory directive, taking account of the entire developmental record pertaining to the matter. If the Standards Committee fails to prepare such draft Reliability Standard, the Board of Trustees may direct NERC management to prepare such draft Reliability Standard.

5.1 The Board of Trustees may, in its discretion, convene a public technical conference to receive input on the matter. The draft Reliability Standard shall be posted for a 45-day public comment period.

5.2 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees finds that the draft Reliability Standard, with such modifications as the Board of Trustees determines are appropriate in light of the comments received, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to approve the draft Reliability Standard and direct that the proposed Reliability Standard be filed with Applicable Governmental Authorities with a request that the proposed Reliability Standard be made effective.

5.3 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees is unable to find that the draft Reliability Standard, even with modifications, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to direct that the draft Reliability Standard and complete developmental record be filed as a compliance filing in response to the regulatory directive with the Applicable Governmental Authority issuing the regulatory directive, with a recommendation that the draft Reliability Standard not be made effective.

5.4 The filing of the Reliability Standard under either paragraph 5.2 or paragraph 5.3 of this Rule shall include an explanation of the basis for the decision by the Board of Trustees.

5.5 A Reliability Standard approved under paragraph 5 of this Rule shall not be eligible for submission as an American National Standard.

6. NERC shall on or before March 31st of each year file a report with Applicable Governmental Authorities on the status and timetable for addressing each outstanding directive to address a specific matter received from an Applicable Governmental Authority.

SECTION 400 — COMPLIANCE ENFORCEMENT

401. Scope of the NERC Compliance Monitoring and Enforcement Program

1. **Components of the NERC Compliance Monitoring and Enforcement Program** — NERC shall develop and implement a NERC Compliance Monitoring and Enforcement Program to promote the reliability of the Bulk Power System by enforcing compliance with approved Reliability Standards in those regions of North American in which NERC and/or a Regional Entity (pursuant to a delegation agreement with NERC that has been approved by the Applicable Governmental Authority) has been given enforcement authority. There are four distinct parts of the NERC Compliance Monitoring and Enforcement Program: (1) NERC's oversight of the Regional Entity Compliance Monitoring and Enforcement Programs (Section 402), (2) the definition of the required Regional Entity Compliance Monitoring and Enforcement Program attributes (Section 403), (3) NERC's monitoring of Regional Entity compliance with Reliability Standards (Section 404), and (4) the monitoring of compliance with Reliability Standards that are applicable to NERC (Sections 405–406).

2. **Who Must Comply** — Where required by applicable legislation, regulation, rule or agreement, all Bulk Power System owners, operators, and users, Regional Entities, and NERC, are required to comply with all approved NERC Reliability Standards at all times. Regional Reliability Standards and Variances approved by NERC and the Applicable Governmental Authority shall be considered NERC Reliability Standards and shall apply to all Bulk Power System owners, operators, or users responsible for meeting those Reliability Standards within the Regional Entity boundaries, whether or not the Bulk Power System owner, operator, or user is a member of the Regional Entity.

3. **Data Access** — All Bulk Power System owners, operators, and users shall provide to NERC and the applicable Regional Entity such information as is necessary to monitor compliance with the Reliability Standards. NERC and the applicable Regional Entity will define the data retention and reporting requirements in the Reliability Standards and compliance reporting procedures.

4. **Role of Regional Entities in the Compliance Monitoring and Enforcement Program** — Each Regional Entity that has been delegated authority through a delegation agreement or other legal instrument approved by the Applicable Governmental Authority shall, in accordance with the terms of the approved delegation agreement, administer a Regional Entity Compliance Monitoring and Enforcement program to meet the NERC Compliance Monitoring and Enforcement Program goals and the requirements in this Section 400.

5. **Program Continuity** — NERC will ensure continuity of compliance monitoring and enforcement within the geographic boundaries of a Regional Entity in the event that NERC does not have a delegation agreement, or the Regional Entity withdraws from the agreement or does not operate its Compliance Monitoring and

Enforcement Program in accordance with the delegation agreement or other applicable requirements.

5.1 Should NERC not have a delegation agreement with a Regional Entity covering a geographic area, or a Regional Entity withdraws from an existing delegation agreement or the delegation agreement is otherwise terminated, NERC will directly administer the Compliance Monitoring and Enforcement Program applicable to owners, operators and users of the Bulk Power System within that geographic area.

1. This monitoring and enforcement will be accomplished by NERC and Compliance Staff from another approved Regional Entity.

2. If an existing delegation agreement with a Regional Entity is terminating, the Regional Entity shall promptly provide to NERC all relevant compliance information regarding Registered Entities, contacts, prior compliance information and actions, Mitigation Plans, and Remedial Action Directives for the period in which the Regional Entity was responsible for administering the Compliance Monitoring and Enforcement Program.

3. NERC will levy and collect all Penalties directly and will utilize any Penalty monies collected to offset the expenses of administering the Compliance Monitoring and Enforcement Program for the geographic area.

5.2 Should a Regional Entity seek to withdraw from its delegation agreement, NERC will seek agreement from another Regional Entity to amend its delegation agreement with NERC to extend that Regional Entity's boundaries for compliance monitoring and enforcement. In the event no Regional Entity is willing to accept this responsibility, NERC will administer the Compliance Monitoring and Enforcement Program within the geographical boundaries of the Regional Entity seeking to withdraw from the delegation agreement, in accordance with Section 401.5.1.

6. **Risk Elements** — NERC, with input from the Regional Entities, stakeholders, and regulators, shall at least annually identify risk elements to prioritize risks to the reliability of the Bulk Power System. These risk elements and related NERC Reliability Standards and Requirements are to be considered for compliance oversight in the annual NERC Compliance Monitoring and Enforcement Program Implementation Plan. NERC identifies the risk elements using data including, but not limited to: compliance findings; event analysis experience; data analysis; and the expert judgment of NERC and Regional Entity staff, committees, and subcommittees. NERC uses these risk elements to identify and prioritize interconnection and continent-wide risks to the reliability of the Bulk Power System. These identified risks, as well as risks to the reliability of the Bulk Power System identified by Regional Entities for their footprint, represent the

focus for monitoring activities in the upcoming year, and become inputs for developing oversight plans for individual Registered Entities. Compliance is required, and NERC and the Regional Entities have authority to monitor compliance, with all applicable NERC Reliability Standards whether or not they are identified as areas of focus to be considered for compliance oversight in the annual NERC Compliance Monitoring and Enforcement Program Implementation Plan or are included in a Regional Entity's oversight plan for the Registered Entity.

7. **Penalties, Sanctions, and Remedial Action Directives** — NERC and Regional Entities will apply Penalties, sanctions, and Remedial Action Directives that bear a reasonable relation to the seriousness of a violation and take into consideration timely remedial efforts as defined in the NERC *Sanction Guidelines*, which is incorporated into these rules as **Appendix 4B**.

8. **Multiple Enforcement Actions** – A Registered Entity shall not be subject to an enforcement action by NERC and a Regional Entity, or by more than one Regional Entity (unless the Registered Entity is registered in more than one Region in which the violation occurred), for the same violation.

9. **Records** — NERC shall maintain a record of each compliance submission, including Self-Reported, Possible, Alleged, and Confirmed Violations of approved Reliability Standards; associated Penalties, sanctions, Remedial Action Directives and settlements; and the status of mitigation actions.

10. **Confidential Information** — NERC will treat all Possible and Alleged Violations of Reliability Standards and matters related to a Compliance Monitoring and Enforcement Program process, including the status of any Compliance Investigation or other Compliance Monitoring and Enforcement Program process, as confidential in accordance with Section 1500.

    The types of information that will be considered confidential and will not (subject to statutory and regulatory requirements) be disclosed in any public information reported by NERC are identified in Section 1500. Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident, will be identified and protected from public disclosure as Critical Energy Infrastructure Information in accordance with Section 1500.

    The Regional Entity and NERC shall give Bulk Power System owners, operators, and users a reasonable opportunity to demonstrate that information concerning a violation is confidential before such report is disclosed to the public.

11. **Public Posting** — When the affected Bulk Power System owner, operator, or user either agrees with a Possible or Alleged Violation(s) of a Reliability Standard(s) or a report of a Compliance Audit or Compliance Investigation, or enters into a settlement agreement concerning a Possible or Alleged Violation(s), or the time for submitting an appeal is passed, or all appeals processes are complete, NERC

shall, subject to the confidentiality requirements of these Rules of Procedure, publicly post each Confirmed Violation, Penalty or sanction, settlement agreement, and final Compliance Audit or Compliance Investigation report, on its website. As required by an Applicable Governmental Authority, NERC will also post information concerning noncompliance disposed of as Compliance Exceptions, subject to Section 1500 of these Rules of Procedures.

11.1 Each Bulk Power System owner, operator, or user may provide NERC with a statement to accompany the Confirmed Violation or report to be posted publicly. The statement must be on company letterhead and include a signature, as well as the name and title of the person submitting the information.

11.2 In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information (*NERC Security Guidelines for the Electricity Sector — Protecting Potentially Sensitive Information* may be used as a guide) or other Confidential Information shall be redacted in accordance with Section 1500 and not be released publicly.

11.3 Subject to redaction of Critical Energy Infrastructure Information or other Confidential Information, for each Confirmed Violation or settlement relating to a Possible Violation or an Alleged Violation, the public posting shall include the name of any relevant entity, the nature, time period, and circumstances of such Possible, Alleged or Confirmed Violation, any Mitigation Plan or other Mitigating Activities to be implemented by the Registered Entity in connection with the Confirmed Violation or settlement, and sufficient facts to assist owners, operators and users of the Bulk Power System to evaluate whether they have engaged in or are engaging in similar activities.

12. **Violation Information Review** — NERC Compliance Staff shall periodically review and analyze all reports of Possible, Alleged and Confirmed Violations to identify trends and other pertinent reliability issues.

402. NERC Oversight of the Regional Entity Compliance Monitoring and Enforcement Programs

1. **NERC Monitoring Program** — NERC shall have a program to monitor the Compliance Monitoring and Enforcement Program of each Regional Entity that has been delegated authority. The objective of this monitoring program shall be to ensure that the Regional Entity carries out its Compliance Monitoring and Enforcement Program in accordance with these Rules of Procedure and the terms of the delegation agreement, and to ensure consistency and fairness of the Regional Entity's Compliance Monitoring and Enforcement Program. Oversight and monitoring by NERC shall be accomplished through an annual Compliance Monitoring and Enforcement Program review, program audits, and regular

evaluations of Regional Entity Compliance Monitoring and Enforcement Program performance as described below.

1.1 **NERC Review of Annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plans** — NERC shall require each Regional Entity to submit for review and approval an annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan. NERC shall review each annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan and shall accept the plan if it meets NERC requirements and the requirements of the delegation agreement.

1.2 **Regional Entity Compliance Monitoring and Enforcement Program Evaluation** — NERC shall annually evaluate the goals, tools, and procedures of each Regional Entity Compliance Monitoring and Enforcement Program to determine the effectiveness of each Regional Entity Compliance Monitoring and Enforcement Program, using criteria developed by the NERC Compliance and Certification Committee.

1.3 **Regional Entity Compliance Monitoring and Enforcement Program Audit** — At least once every five years, NERC shall conduct an audit to evaluate how each Regional Entity Compliance Monitoring and Enforcement Program implements the NERC Compliance Monitoring and Enforcement Program. The evaluation shall be based on these Rules of Procedure, including Appendix 4C, the delegation agreement, directives in effect pursuant to the delegation agreement, approved annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plans, required Compliance Monitoring and Enforcement Program attributes, and the NERC Compliance Monitoring and Enforcement Program procedures. These evaluations shall be provided to the Applicable Governmental Authorities to demonstrate the effectiveness of each Regional Entity. In addition, audits of Cross-Border Regional Entities shall cover applicable requirements imposed on the Regional Entity by statute, regulation, or order of, or agreement with, provincial governmental and/or regulatory authorities for which NERC has auditing responsibilities over the Regional Entity's compliance with such requirements within Canada or Mexico. Participation of a representative of an Applicable Governmental Authority shall be subject to the limitations of sections 3.1.6 and 8.0 of Appendix 4C of these Rules of Procedure regarding disclosures of non-public compliance information related to other jurisdictions. NERC shall maintain an audit procedure containing the requirements, steps, and timelines to conduct an audit of each Regional Entity Compliance Monitoring and Enforcement Program. The current procedure is contained in the NERC Audit of Regional Entity Compliance Programs, which is incorporated into these rules as **Appendix 4A**.

1.3.1. NERC shall establish a program to audit bulk power system owners, operators, and users operating within a regional entity to verify the findings of previous compliance audits conducted by the regional entity to evaluate how well the regional entity compliance enforcement program is meeting its delegated authority and responsibility.

1.4 Applicable Governmental Authorities will be allowed to participate as an observer in any audit conducted by NERC of a Regional Entity's Compliance Monitoring and Enforcement Program. A representative of the Regional Entity being audited will be allowed to participate in the audit as an observer.

2. **Consistency Among Regional Compliance Monitoring and Enforcement Programs** — To provide for a consistent Compliance Monitoring and Enforcement Program for all Bulk Power System owners, operators, and users required to comply with approved Reliability Standards, NERC shall maintain a single, uniform Compliance Monitoring and Enforcement Program, which is incorporated into these rules of procedure as **Appendix 4C**. Any differences in Regional Entity Compliance Monitoring and Enforcement Program methods, including determination of violations and Penalty assessment, shall be justified on a case-by-case basis and fully documented in each Regional Entity delegation agreement.

2.1 NERC shall ensure that each of the Regional Entity Compliance Monitoring and Enforcement Programs meets these Rules of Procedure, including **Appendix 4C**, and follows the terms of the delegation agreement and the approved annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan.

2.2 NERC shall maintain a single, uniform Compliance Monitoring and Enforcement Program in **Appendix 4C** containing the procedures to ensure the consistency and fairness of the processes used to determine Regional Entity Compliance Monitoring and Enforcement Program findings of compliance and noncompliance, and the application of Penalties and sanctions.

2.3 NERC shall periodically conduct Regional Entity compliance manager forums. These forums shall use the results of Regional Entity Compliance Monitoring and Enforcement Program audits and findings of NERC Compliance Staff to identify and refine Regional Entity Compliance Monitoring and Enforcement Program differences into a set of best practices over time.

3. **Information Collection and Reporting** — NERC and the Regional Entities shall implement data management procedures that address data reporting requirements, data integrity, data retention, data security, and data confidentiality.

4. **Violation Disclosure** — NERC shall disclose all Confirmed Violations and maintain as confidential Possible Violations and Alleged Violations, according to the reporting and disclosure process in **Appendix 4C**.

5. **Authority to Determine Noncompliance, Levy Penalties and Sanctions, and Issue Remedial Action Directives** — NERC and Regional Entity Compliance Staff shall have the authority and responsibility to make initial determinations of compliance or noncompliance, and where authorized by the Applicable Governmental Authorities or where otherwise authorized, to determine Penalties and sanctions for noncompliance with a Reliability Standard, and issue Remedial Action Directives. Regional Entity boards or a compliance panel reporting directly to the Regional Entity board will be vested with the authority for the overall Regional Entity Compliance Monitoring and Enforcement Program and have the authority to impose Penalties and sanctions on behalf of NERC, where authorized by applicable legislation or agreement. Remedial Action Directives may be issued by NERC or a Regional Entity that is aware of a Bulk Power System owner, operator, or user that is, or is about to engage in an act or practice that would result, in noncompliance with a Reliability Standard, where such Remedial Action Directive is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat. If, after receiving such a Remedial Action Directive, the Bulk Power System owner, operator, or user does not take appropriate action to avert a violation of a Reliability Standard, NERC may petition the Applicable Governmental Authority to issue a compliance order.

6. **Due Process** — NERC shall establish and maintain a fair, independent, and nondiscriminatory appeals process. The appeals process is set forth in Sections 408-410. The process shall allow Bulk Power System owners, operators, and users to appeal the Regional Entity's findings of noncompliance and to appeal Penalties, sanctions, and Remedial Action Directives that are levied by the Regional Entity. Appeals beyond the NERC process will be heard by the Applicable Governmental Authority.

   The appeals process will also allow for appeals to NERC of any findings of noncompliance issued by NERC to a Regional Entity for Reliability Standards and Requirements where the Regional Entity is monitored for compliance to a Reliability Standard. No monetary Penalties will be levied in these matters; however sanctions, remedial actions, and directives to comply may be applied by NERC.

7. **Conflict Disclosure** — NERC shall disclose to the appropriate governmental authorities any potential conflicts between a market rule and the enforcement of a Regional Reliability Standard.

8. **Confidentiality** — To maintain the integrity of the NERC Compliance Monitoring and Enforcement Program, NERC and Regional Entity staff, Compliance Audit team members, and committee members shall maintain the

confidentiality of information obtained and shared during compliance monitoring and enforcement processes including Compliance Investigations, Compliance Audits, Spot Checks, drafting of reports, appeals, and closed meetings.

8.1 NERC and the Regional Entity shall have in place appropriate codes of conduct and confidentiality agreements for staff and other Compliance Monitoring and Enforcement Program participants.

8.2 Individuals not bound by NERC or Regional Entity codes of conduct who serve on compliance-related committees or Compliance Audit teams shall sign a NERC confidentiality agreement prior to participating on the committee or Compliance Audit team.

8.3 Information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information shall not be distributed outside of a committee or team, nor released publicly. Other information subject to confidentiality is identified in Section 1500.

8.4 In the event that a staff, committee, or Compliance Audit team member violates any of the confidentiality rules set forth above, the staff, committee, or Compliance Audit team member and any member organization with which the individual is associated may be subject to appropriate action by the Regional Entity or NERC, including prohibiting participation in future Compliance Monitoring and Enforcement Program activities.

9. **Auditor Training** — NERC shall develop and provide training in auditing skills to all people who participate in NERC and Regional Entity Compliance Audits. Training for NERC and Regional Entity personnel and others who serve as Compliance Audit team leaders shall be more comprehensive than training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

403. Required Attributes of Regional Entity Compliance Monitoring and Enforcement Programs

Each Regional Entity Compliance Monitoring and Enforcement Program shall promote excellence in the enforcement of Reliability Standards. To accomplish this goal, each Regional Entity Compliance Monitoring and Enforcement Program shall (i) conform to and comply with the NERC uniform Compliance Monitoring and Enforcement Program, **Appendix 4C** to these Rules of Procedure, except to the extent of any deviations that are stated in the Regional Entity's delegation agreement, and (ii) meet all of the attributes set forth in this Section 403.

Program Structure

1. **Independence** — Each Regional Entity's governance of its Compliance Monitoring and Enforcement Program shall exhibit independence, meaning the Compliance Monitoring and Enforcement Program shall be organized so that its compliance monitoring and enforcement activities are carried out separately from other activities of the Regional Entity. The Compliance Monitoring and Enforcement Program shall not be unduly influenced by the Bulk Power System owners, operators, and users being monitored or other Regional Entity activities that are required to meet the Reliability Standards. Regional Entities must include rules providing that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

2. **Exercising Authority** — Each Regional Entity Compliance Monitoring and Enforcement Program shall exercise the responsibility and authority in carrying out the delegated functions of the NERC Compliance Monitoring and Enforcement Program in accordance with delegation agreements and **Appendix 4C**. These functions include but are not limited to: data gathering, data reporting, Compliance Investigations, Compliance Audit activities, evaluating compliance and noncompliance, imposing Penalties and sanctions, and approving and tracking mitigation actions.

3. **Delegation of Authority** — To maintain independence, fairness, and consistency in the NERC Compliance Monitoring and Enforcement Program, a Regional Entity shall not sub-delegate its Compliance Monitoring and Enforcement Program duties to entities or persons other than the Regional Entity Compliance Staff, unless (i) required by statute or regulation in the applicable jurisdiction, or (ii) by agreement with express approval of NERC and of FERC or other Applicable Governmental Authority, to another Regional Entity.

4. **Hearings of Contested Findings or Sanctions —** The Regional Entity board or compliance panel reporting directly to the Regional Entity board will designate a Hearing Body (with appropriate recusal procedures) that will be vested with the authority for conducting all compliance hearings, pursuant to the hearing process selected under Section 403.15, in which any Bulk Power System owner, operator, or user provided a Notice of Alleged Violation may present facts and other information to contest a Notice of Alleged Violation or any proposed Penalty, sanction, any Remedial Action Directive, or any Mitigation Plan component. Compliance hearings shall be conducted in accordance with the Hearing Procedures set forth in Attachment 2 to **Appendix 4C**. If a stakeholder body serves as the Hearing Body, no two industry sectors may control any decision and no single sector may veto any matter related to compliance after recusals.

Program Resources

5. **Regional Entity Compliance Staff** — Each Regional Entity shall have sufficient resources to meet delegated compliance monitoring and enforcement responsibilities, including the necessary professional staff to manage and

implement the Regional Entity Compliance Monitoring and Enforcement Program.

6. **Regional Entity Compliance Staff Independence** — The Regional Entity Compliance Staff shall be capable of and required to make all determinations of compliance and noncompliance and determine Penalties, sanctions, and Remedial Action Directives and to review and accept Mitigation Plans and other Mitigating Activities.

   6.1 Regional Entity Compliance Staff shall not have a conflict of interest, real or perceived, in the outcome of compliance monitoring and enforcement processes, reports, or sanctions. The Regional Entity shall have in effect a conflict of interest policy.

   6.2 Regional Entity Compliance Staff shall have the authority and responsibility to carry out compliance monitoring and enforcement processes (with the input of industry subject matter experts), make determinations of compliance or noncompliance, and levy Penalties and sanctions without interference or undue influence from Regional Entity members and their representative or other industry entities.

   6.3 Regional Entity Compliance Staff may call upon independent technical subject matter experts who have no conflict of interest in the outcome of the compliance monitoring and enforcement process to provide technical advice or recommendations in the determination of compliance or noncompliance.

   6.4 Regional Entity Compliance Staff shall abide by the confidentiality requirements contained in Section 1500 and **Appendix 4C** of these Rules of Procedure, the NERC delegation agreement and other confidentiality agreements required by the NERC Compliance Monitoring and Enforcement Program.

   6.5 Contracting with independent consultants or others working for the Regional Entity Compliance Monitoring and Enforcement Program shall be permitted provided the individual has not received compensation from a Bulk Power System owner, operator, or user being monitored for a period of at least the preceding six months and owns no financial interest in any Bulk Power System owner, operator, or user being monitored for compliance to the Reliability Standard, regardless of where the Bulk Power System owner, operator, or user operates. Any such individuals for the purpose of these Rules of Procedure shall be considered as augmenting Regional Entity Compliance Staff.

7. **Use of Industry Subject Matter Experts and Regional Entity Members** — Industry experts and Regional Entity members may be called upon to provide

their technical expertise in Compliance Monitoring and Enforcement Program activities.

7.1 The Regional Entity shall have procedures defining the allowable involvement of industry subject matter experts and Regional Entity members. The procedures shall address applicable antitrust laws and conflicts of interest.

7.2 Industry subject matter experts and Regional Entity members shall have no conflict of interest or financial interests in the outcome of their activities.

7.3 Regional Entity members and industry subject matter experts, as part of teams or Regional Entity committees, may provide input to the Regional Entity Compliance Staff so long as the authority and responsibility for (i) evaluating and determining compliance or noncompliance and (ii) levying Penalties, sanctions, or Remedial Action Directives shall not be delegated to any person or entity other than the Compliance Staff of the Regional Entity. Industry subject matter experts, Regional Entity members, or Regional Entity committees shall not make determinations of noncompliance or levy Penalties, sanctions, or Remedial Action Directives. Any committee involved shall be organized so that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

7.4 Industry subject matter experts and Regional Entity members shall sign a confidentiality agreement appropriate for the activity being performed.

7.5 All industry subject matter experts and Regional Entity members participating in Compliance Audits and Compliance Investigations shall successfully complete auditor training provided by NERC or the Regional Entity prior to performing these activities

Program Design

8. **Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan Content** — All approved Reliability Standards shall be included in the Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan for all Bulk Power System owners, operators, and users within the defined boundaries of the Regional Entity. Compliance to approved Regional Reliability Standards is applicable only within the Region of the Regional Entity that submitted those particular Regional Reliability Standards for approval. NERC will identify the risk elements and related Reliability Standards and Requirements to be considered by the Regional Entity in a given year in developing oversight plans for individual Registered Entities.

9. **Antitrust Provisions** — Each Regional Entity's Compliance Monitoring and Enforcement Program shall be structured and administered to abide by U.S. antitrust law and Canadian competition law.

10. **Information Submittal** — All Bulk Power System owners, operators, and users within the Regional Entity responsible for complying with Reliability Standards shall submit timely and accurate information when requested by the Regional Entity or NERC. NERC and the Regional Entities shall preserve any mark of confidentiality on information submitted pursuant to Section 1502.1.

    10.1 Each Regional Entity has the authority to collect the necessary information to determine compliance and shall develop processes for gathering data from the Bulk Power System owners, operators, and users the Regional Entity monitors.

    10.2 The Regional Entity or NERC has the authority to request information from Bulk Power System owners, operators, and users pursuant to Section 401.3 or this Section 403.10 without invoking a specific compliance monitoring and enforcement process in **Appendix 4C**, for purposes of determining whether to pursue one such process in a particular case and/or validating in the enforcement phase of a matter the conclusions reached through the compliance monitoring and enforcement process(es).

    10.3 When required or requested, the Regional Entities shall report information to NERC promptly and in accordance with **Appendix 4C** and other NERC procedures.

    10.4 Regional Entities shall notify NERC of all Possible, Alleged and Confirmed Violations of NERC Reliability Standards by Registered Entities over which the Regional Entity has compliance monitoring and enforcement authority, in accordance with **Appendix 4C**.

    10.5 A Bulk Power System owner, operator, or user found in noncompliance with a Reliability Standard shall submit a Mitigation Plan with a timeline addressing how the noncompliance will be corrected, unless an enforcement process is used that does not require a Mitigation Plan. The Regional Entity Compliance Staff shall review and accept the Mitigation Plan in accordance with **Appendix 4C**.

    10.6 An officer of a Bulk Power System owner, operator, or user shall certify as accurate all compliance data Self-Reported to the Regional Entity Compliance Monitoring and Enforcement Program.

    10.7 Regional Entities shall develop and implement procedures to verify the compliance information submitted by Bulk Power System owners, operators, and users.

11. **Compliance Audits of Bulk Power System Owners, Operators, and Users** — Each Regional Entity will maintain and implement a program of proactive Compliance Audits of Bulk Power System owners, operators, and users responsible for complying with Reliability Standards, in accordance with **Appendix 4C**. A Compliance Audit is a process in which a detailed review of the activities of a Bulk Power System owner, operator, or user is performed to determine if that Bulk Power System owner, operator, or user is complying with approved Reliability Standards.

    11.1 For an entity registered as a Balancing Authority, Reliability Coordinator, or Transmission Operator, the Compliance Audit will be performed at least once every three years. For other Bulk Power System owners, operators, and users on the NERC Compliance Registry, Compliance Audits shall be performed on a schedule established by NERC.

    11.2 Compliance Audits of Balancing Authorities, Reliability Coordinators, and Transmission Operators will include a component at the audited entity's site. For other Bulk Power System owners, operators, and users on the NERC Compliance Registry, the Compliance Audit may be either an on-site Compliance Audit or based on review of documents, as determined to be necessary and appropriate by NERC or Regional Entity Compliance Staff.

    11.3 Compliance Audits must include a detailed review of the activities of the Bulk Power System owner, operator, or user to determine if the Bulk Power System owner, operator, or user is complying with all approved Reliability Standards identified for audit by NERC. The Compliance Audit shall include a review of supporting documentation and evidence used by the Bulk Power System owner, operator or user to demonstrate compliance for an appropriate period prior to the Compliance Audit.

12. **Confidentiality of Compliance Monitoring and Enforcement Processes** — All compliance monitoring and enforcement processes, and information obtained from such processes, are to be non-public and treated as confidential in accordance with Section 1500 and **Appendix 4C** of these Rules of Procedure, unless NERC, the Regional Entity or FERC or another Applicable Governmental Authority with jurisdiction determines a need to conduct a Compliance Monitoring and Enforcement Program process on a public basis, provided, that NERC and the Regional Entities shall publish (i) schedules of Compliance Audits scheduled in each year, (ii) a public report of each Compliance Audit, and (iii) Notices of Penalty and settlement agreements. Advance authorization from the Applicable Governmental Authority is required to make public any compliance monitoring and enforcement process or any information relating to a compliance monitoring and enforcement process, or to permit interventions when determining whether to impose a Penalty. This prohibition on making public any compliance monitoring and enforcement process does not prohibit NERC or a Regional Entity from publicly disclosing (i) the initiation of or results from an analysis of a

significant system event under Section 807 or of off-normal events or system performance under Section 808, or (ii) information of general applicability and usefulness to owners, operators, and users of the Bulk Power System concerning reliability and compliance matters, so long as specific allegations or conclusions regarding Possible or Alleged Violations of Reliability Standards are not included in such disclosures.

13. **Critical Energy Infrastructure Information** — Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident will be identified and protected from public disclosure as Critical Energy Infrastructure Information. In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information shall be redacted according to NERC procedures and shall not be released publicly.

14. **Penalties, Sanctions, and Remedial Action Directives** — Each Regional Entity will apply all Penalties, sanctions, and Remedial Action Directives in accordance with the approved *Sanction Guidelines*, **Appendix 4B** to these Rules of Procedure. Any changes to the *Sanction Guidelines* to be used by any Regional Entity must be approved by NERC and submitted to the Applicable Governmental Authority for approval. All Confirmed Violations, Penalties, and sanctions, including Confirmed Violations, Penalties and sanctions specified in a Regional Entity Hearing Body decision, will be provided to NERC for review and filing with Applicable Governmental Authorities as a Notice of Penalty, in accordance with **Appendix 4C**.

15. **Hearing Process** — Each Regional Entity shall adopt either the Regional Entity Hearing Process (Section 403.15A) or the Consolidated Hearing Process (403.15B) and conduct all hearings pursuant to the selected process. In either case, the selected hearing process shall be a fair, independent, and nondiscriminatory process for hearing contested violations and any Penalties or sanctions levied, in conformance with Attachment 2 to **Appendix 4C** to these Rules of Procedure and any deviations therefrom that are set forth in the Regional Entity's delegation agreement. The hearing process shall allow Bulk Power System owners, operators, and users to contest findings of compliance violations, any Penalties and sanctions that are proposed to be levied, proposed Remedial Action Directives, and components of proposed Mitigation Plans. The hearing process shall (i) include provisions for recusal of any members of the Hearing Body with a potential conflict of interest, real or perceived, from all compliance matters considered by the Hearing Body for which the potential conflict of interest exists and (ii) provide that no two industry sectors may control any decision and no single sector may veto any matter brought before the Hearing Body after recusals.

    A Regional Entity may modify its selection of hearing process by giving notice to NERC six (6) months prior to such modification becoming effective. Hearings

will be conducted pursuant to the process in effect at the Regional Entity at the time of the submission of the hearing request by the registered entity.

Each Regional Entity will notify NERC of all hearings and NERC may observe any of the proceedings. Each Regional Entity will notify NERC of the outcome of all hearings.

If a Bulk Power System owner, operator, or user or a Regional Entity has completed the Regional Entity Hearing Process or the Consolidated Hearing Process and desires to appeal the outcome of the hearing, the Bulk Power System owner, operator, or user or the Regional Entity shall appeal to NERC in accordance with Section 409 of these Rules of Procedure, except that a determination of violation or Penalty that has been directly adjudicated by an Applicable Governmental Authority shall be appealed with that Applicable Governmental Authority.

15A. **Regional Entity Hearing Process** — The Regional Entity Hearing Process shall be conducted before a Hearing Body composed of the Regional Entity board or a balanced committee established by and reporting to the Regional Entity board as the final adjudicator at the Regional Entity level, provided, that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions.

15B. **Consolidated Hearing Process** — The Consolidated Hearing Process shall be conducted before a Hearing Body composed of five members, unless a smaller number is necessary, as discussed below. The Hearing Body will issue a final decision, provided that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions. Up to two members will be appointed by the Regional Entity from which the case originates. If stakeholder members are appointed, the stakeholders shall not represent the same industry sector. Should a Regional Entity choose to appoint one or no representative, then the NERC Board of Trustees Compliance Committee will select additional representatives to fill those vacancies. The Compliance Committee will appoint the NERC representatives to the Hearing Body, chosen among NERC trustees not serving on the Compliance Committee at the time of the request for hearing. The Regional Entity and NERC members appointed to the Hearing Body will appoint an additional member to the Hearing Body, chosen among NERC trustees not serving on the Compliance Committee at the time of the request for hearing or from the Regional Entity which the case originates. If the Hearing Body does not select a NERC trustee or a regional representative, the Hearing Body will appoint an additional member in accordance with the criteria specified in Appendix 4C, Attachment 2, Section 1.4.3(a). In the event a Regional Entity chooses not to appoint representatives to the Hearing Body and there are not five NERC trustees available to participate on the Hearing Body, as determined by the Compliance Committee, the Hearing Body may be composed of three members (three NERC trustees not serving on the Compliance Committee). The Hearing Body will appoint a Hearing Officer to preside over the hearing.

16. **Annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan** — Each Regional Entity shall annually develop and submit to NERC for approval a Regional Entity Compliance Monitoring and Enforcement Implementation Plan in accordance with **Appendix 4C** that, includes details on regional risk assessment processes and results, Reliability Standards and Requirements associated with regional risk assessment results, the methods to be used by the Regional Entity for reporting, monitoring, evaluating, and assessing performance criteria and the Regional Entity's Annual Audit Plan. These Regional Implementation Plans will be submitted to NERC on the schedule established by NERC, generally on or about October 1 of the preceding year. In conjunction with the annual Regional Implementation Plan, each Regional Entity must report to NERC regarding how it carried out its delegated compliance monitoring and enforcement authority in the previous year, the effectiveness of the Compliance Monitoring and Enforcement Program, and changes expected to correct any deficiencies identified. Each Regional Entity will provide its annual report on the schedule established by NERC, generally on or about February 15 of the following year.

404. NERC Monitoring of Compliance for Regional Entities or Bulk Power Owners, Operator, or Users

NERC shall monitor Regional Entity compliance with NERC Reliability Standards and, if no there is no delegation agreement in effect with a Regional Entity for the geographic area, shall monitor Bulk Power System owners, operators, and users for compliance with NERC Reliability Standards. Industry subject matter experts may be used as appropriate in Compliance Investigations, Compliance Audits, and other Compliance Monitoring and Enforcement Program activities, subject to confidentiality, antitrust, and conflict of interest provisions.

1. **NERC Obligations** — NERC Compliance Staff shall monitor the compliance of the Regional Entity with the Reliability Standards for which the Regional Entities are responsible, in accordance with **Appendix 4C**. NERC shall actively monitor in its annual Compliance Enforcement and Monitoring Program selected Reliability Standards that apply to the Regional Entities. NERC shall evaluate compliance and noncompliance with all of the Reliability Standards that apply to the Regional Entities and shall impose sanctions, Penalties, or Remedial Action Directives when there is a finding of noncompliance. NERC shall post all violations of Reliability Standards that apply to the Regional Entities as described in the reporting and disclosure process in **Appendix 4C**.

   In addition, NERC will directly monitor Bulk Power System owners, operators, and users for compliance with NERC Reliability Standards in any geographic area for which there is not a delegation agreement in effect with a Regional Entity, in accordance with **Appendix 4C**. In such cases, NERC will serve as the Compliance Enforcement Authority described in **Appendix 4C**. Compliance matters contested by Bulk Power System owners, operators, and users in such an event will be heard by the NERC Compliance and Certification Committee.

2. **Compliance Audit of the Regional Entity** — NERC shall perform a Compliance Audit of each Regional Entity responsible for complying with Reliability Standards at least once every three years. NERC shall make an evaluation of compliance based on the information obtained through the Compliance Audit. After due process is complete, the final Compliance Audit report shall be made public in accordance with the reporting and disclosure process in **Appendix 4C**.

3. **Appeals Process** — Any Regional Entity or Bulk Power System owner, operator or user found by NERC, as opposed to a Regional Entity, to be in noncompliance with a Reliability Standard may appeal the findings of noncompliance with Reliability Standards and any sanctions or Remedial Action Directives that are issued by, or Mitigation Plan components imposed by, NERC, pursuant to the processes described in Sections 408 through 410.

405. Monitoring of Reliability Standards and Other Requirements Applicable to NERC

The NERC Compliance and Certification Committee shall establish and implement a process to monitor NERC's compliance with the Reliability Standards that apply to NERC. The process shall use independent monitors with no conflict of interest, real or perceived, in the outcomes of the process. All violations shall be made public according to the reporting and disclosure process in **Appendix 4C**. The Compliance and

Certification Committee will also establish a procedure for monitoring NERC's compliance with its Rules of Procedure for the Standards Development, Compliance Monitoring and Enforcement, and Organization Registration and Certification Programs. Such procedures shall not be used to circumvent the appeals processes established for those programs.

406. Independent Audits of the NERC Compliance Monitoring and Enforcement Program

NERC shall provide for an independent audit of its Compliance Monitoring and Enforcement Program at least once every three years, or more frequently as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board. The independent audit shall meet the following minimum requirements and any other requirements established by the NERC Board.

1. **Effectiveness** — The audit shall evaluate the success and effectiveness of the NERC Compliance Monitoring and Enforcement Program in achieving its mission.

2. **Relationship** — The audit shall evaluate the relationship between NERC and the Regional Entity Compliance Monitoring and Enforcement Programs and the effectiveness of the programs in ensuring reliability.

3. **Final Report Posting** — The final report shall be posted by NERC for public viewing in accordance with **Appendix 4C**.

4. **Response to Recommendations** — If the audit report includes recommendations to improve the NERC Compliance Monitoring and Enforcement Program, the administrators of the NERC Compliance Monitoring and Enforcement Program shall provide a written response and plan to the Board within 30 days of the release of the final audit report.

407. Penalties, Sanctions, and Remedial Action Directives

1. **NERC Review of Regional Entity Penalties and Sanctions —** NERC shall review all Penalties, sanctions, and Remedial Action Directives imposed by each Regional Entity for violations of Reliability Standards, including Penalties, sanctions and Remedial Action Directives that are specified by a Hearing Body final decision issued pursuant to Attachment 2 to **Appendix 4C**, to determine if the Regional Entity's determination is supported by a sufficient record compiled by the Regional Entity, is consistent with the *Sanction Guidelines* incorporated into these Rules of Procedure as **Appendix 4B** and with other directives, guidance and directions issued by NERC pursuant to the delegation agreement, and is consistent with Penalties, sanctions and Remedial Action Directives imposed by the Regional Entity and by other Regional Entities for violations involving the same or similar facts and circumstances.

2. **Developing Penalties and Sanctions** — The Regional Entity Compliance Staff shall use the *Sanction Guidelines*, which are incorporated into these Rules of

Procedure as **Appendix 4B**, to develop an appropriate Penalty, sanction, or Remedial Action Directive for a violation, and shall notify NERC of the Penalty, sanction or Remedial Action Directive.

3. **Effective Date of Penalty** — Where authorized by applicable legislation or agreement, no Penalty imposed for a violation of a Reliability Standard shall take effect until the thirty-first day after NERC files, with the Applicable Governmental Authority, a "Notice of Penalty" and the record of the proceedings in which the violation and Penalty were determined, or such other date as ordered by the Applicable Governmental Authority.

408. Review of NERC Decisions

1. **Scope of Review** — A Registered Entity or a Regional Entity wishing to challenge a finding of noncompliance and the imposition of a Penalty for a compliance measure directly administered by NERC, or a Regional Entity wishing to challenge a Regional Entity Compliance Monitoring and Enforcement Program audit finding, may do so by filing a notice of the challenge with NERC's Director of Enforcement no later than 21 days after issuance of the notice of finding of violation or audit finding. Appeals by Registered Entities or Regional Entities of decisions of Hearing Bodies shall be pursuant to Section 409.

2. **Contents of Notice** — The notice of challenge shall include the full text of the decision that is being challenged, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief.

3. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of challenge, the NERC Director of Enforcement may file with the Hearing Panel a response to the issues raised in the notice, with a copy to the Regional Entity.

4. **Hearing by Compliance and Certification Committee** — The NERC Compliance and Certification Committee shall provide representatives of the Regional Entity or Registered Entity, and the NERC Compliance Monitoring and Enforcement Program an opportunity to be heard and shall decide the matter based upon the filings and presentations made, with a written explanation of its decision.

5. **Appeal** — The Regional Entity or Registered Entity may appeal the decision of the Compliance and Certification Committee by filing a notice of appeal with NERC's Director of Enforcement no later than 21 days after issuance of the written decision by the Compliance and Certification Committee. The notice of appeal shall include the full text of the written decision of the Compliance and Certification Committee that is being appealed, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be

presented in the appeal that was not presented to the Compliance and Certification Committee.

6. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of appeal, the NERC Compliance Monitoring and Enforcement Program staff may file its response to the issues raised in the notice of appeal, with a copy to the entity filing the notice.

7. **Reply** — The entity filing the appeal may file a reply within 7 days.

8. **Decision** — The Compliance Committee of the NERC Board of Trustees shall decide the appeal, in writing, based upon the notice of appeal, the record, the response, and any reply. At its discretion, the Compliance Committee may invite representatives of the Regional Entity or Registered Entity, and the NERC Compliance Monitoring and Enforcement Program to appear before the Compliance Committee. Decisions of the Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

9. **Impartiality** — No member of the Compliance and Certification Committee or the Board of Trustees Compliance Committee having an actual or perceived conflict of interest in the matter may participate in any aspect of the challenge or appeal except as a party or witness.

10. **Expenses** — Each party in the challenge and appeals processes shall pay its own expenses for each step in the process.

11. **Non-Public Proceedings —** All challenges and appeals shall be closed to the public to protect Confidential Information.

409. Appeals from Final Decisions of Hearing Bodies

1. **Time for Appeal** — A Regional Entity acting as the Compliance Enforcement Authority, or an owner, operator or user of the Bulk Power System, shall be entitled to appeal from a final decision of a Hearing Body concerning an Alleged Violation of a Reliability Standard, a proposed Penalty or sanction for violation of a Reliability Standard, a proposed Mitigation Plan, or a proposed Remedial Action Directive, by filing a notice of appeal with NERC's Director of Enforcement, with copies to the Clerk, the Regional Entity, and any other Participants in the Hearing Body proceeding, no later than 21 days after issuance of the final decision of the Hearing Body. The Compliance Committee shall render its decision within 180 days following the receipt by NERC's Director of Enforcement of the notice of appeal. The Compliance Committee may extend this deadline for good cause and shall provide written notice of any extension to all Participants.

2. **Contents** — The notice of appeal shall include the full text of the final decision of the Hearing Body that is being appealed, a concise statement of the error or errors contained in the final decision, a clear statement of the relief being sought,

and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not first presented during the proceeding before the Hearing Body.

3. **Response to Notice of Appeal** — Within 21 days after the date the notice of appeal is filed, the Clerk shall file the entire record of the Hearing Body proceeding with NERC's Director of Enforcement, with a copy to all Participants. Within 35 days after the date of the notice of appeal, all Participants in the proceeding before the Hearing Body, other than the Participant filing the notice of appeal, shall file their responses to the issues raised in the notice of appeal.

4. **Reply** — The party filing the appeal may file a reply to the responses within 7 days.

5. **Decision** — The Compliance Committee of the NERC Board of Trustees shall decide the appeal, in writing, based upon the notice of appeal, the record of the proceeding before the Hearing Body, the responses, and any reply filed with NERC. The Compliance Committee shall review the appealed issue(s) under a *de novo* standard. At its discretion, the Compliance Committee may invite representatives of the entity making the appeal and the other Participants in the proceeding before the Hearing Body to appear before the Committee. Decisions of the Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

6. **Expenses** — Each party in the appeals process shall pay its own expenses for each step in the process.

7. **Non-Public Proceedings** — All appeals shall be closed to the public to protect Confidential Information.

8. **Appeal of Hearing Body Decisions Granting or Denying Motions to Intervene** — This section is not applicable to an appeal of a decision of a Hearing Body granting or denying a motion to intervene in the Hearing Body proceeding. Appeals of decisions of Hearing Bodies granting or denying motions to intervene in Hearing Body proceedings shall be processed and decided pursuant to Section 414.

410. Hold Harmless

A condition of invoking the challenge or appeals processes under Section 408 or 409 is that the entity requesting the challenge or appeal agrees that neither NERC (defined to include its Members, Board of Trustees, committees, subcommittees, staff and industry subject matter experts), any person assisting in the challenge or appeals processes, nor any company employing a person assisting in the challenge or appeals processes, shall be liable, and they shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the challenge or appeals proceeding. This "hold harmless"

clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

411. Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards

A Registered Entity that is subject to an Applicable Requirement of a NERC Critical Infrastructure Protection Standard for which Technical Feasibility Exceptions are permitted, may request a Technical Feasibility Exception to the Requirement, and the request will be reviewed, approved or disapproved, and if approved, implemented, in accordance with the NERC *Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standard*, Appendix 4D to these Rules of Procedure.

412. Certification of Questions from Hearing Bodies for Decision by the NERC Board of Trustees Compliance Committee

1. A Hearing Body that is conducting a hearing concerning a disputed compliance matter pursuant to Attachment 2, Hearing Procedures, of Appendix 4C, may certify to the Board of Trustees Compliance Committee, for decision, a significant question of law, policy or procedure the resolution of which may be determinative of the issues in the hearing in whole or in part, and as to which there are other extraordinary circumstances that make prompt consideration of the question by the Compliance Committee appropriate, in accordance with Section 1.5.12 of the Hearing Procedures. All questions certified by a Hearing Body to the Board of Trustees Compliance Committee shall be considered and disposed of by the Compliance Committee.

2. The Compliance Committee may accept or reject a certification of a question for decision. If the Compliance Committee rejects the certified question, it shall issue a written statement that the certification is rejected.

3. If the Compliance Committee accepts the certification of a question for decision, it shall establish a schedule by which the Participants in the hearing before the Hearing Body may file memoranda and reply memoranda stating their positions as to how the question certified for decision should be decided by the Compliance Committee. The Compliance Committee may also request, or provide an opportunity for, the NERC compliance operations department, the NERC compliance enforcement department, and/or the NERC general counsel to file memoranda stating their positions as to how the question certified for decision should be decided. After receiving such memoranda and reply memoranda as are filed in accordance with the schedule, the Compliance Committee shall issue a written decision on the certified question.

4. Upon receiving the Compliance Committee's written decision on the certified question, the Hearing Body shall proceed to complete the hearing in accordance with the Compliance Committee's decision.

5. The Compliance Committee's decision, if any, on the certified question shall only be applicable to the hearing from which the question was certified and to the Participants in that hearing.

413. Review and Processing of Hearing Body Final Decisions that Are Not Appealed

NERC shall review and process all final decisions of Hearing Bodies issued pursuant to Attachment 2 to Appendix 4C concerning an Alleged Violation, proposed Penalty or sanction, or proposed Mitigation Plan that are not appealed pursuant to Section 409, as though the determination had been made by the Regional Entity Compliance Monitoring and Enforcement Program. NERC shall review and process such final decisions, and may require that they be modified by the Regional Entity, in accordance with, as applicable to the particular decision, Sections 5.8, 5.9 and 6.5 of Appendix 4C.

414. Appeals of Decisions of Hearing Bodies Granting or Denying Motions to Intervene in Hearing Body Proceedings

1. **Time to Appeal** — An entity may appeal a decision of a Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** denying the entity's motion to intervene in a Hearing Body proceeding, and the Regional Entity Compliance Staff or any other Participant in the Hearing Body proceeding may appeal a decision of the Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** granting or denying a motion to intervene in the Hearing Body proceeding, in either case by filing a notice of appeal with the NERC Director of Enforcement, with copies to the Clerk of the Hearing Body, the Hearing Body, the Hearing Officer, the Regional Entity Compliance Staff, and all other Participants in the Hearing Body proceeding, no later than seven (7) days following the date of the Hearing Body decision granting or denying the motion to intervene.

2. **Contents of Notice of Appeal** — The notice of appeal shall set forth information and argument to demonstrate that the decision of the Hearing Body granting or denying the motion to intervene was erroneous under the grounds for intervention specified in Section 1.4.4 of Attachment 2 of **Appendix 4C** and that the entity requesting intervention should be granted or denied intervention, as applicable. Facts alleged in, and any offers of proof made in, the notice of appeal shall be supported by affidavit or verification. The notice of appeal shall include a copy of the original motion to intervene and a copy of the decision of the Hearing Body granting or denying the motion to intervene.

3. **Responses to Notice of Appeal** — Within ten (10) days following the date the notice of appeal is filed, the Clerk shall transmit to the NERC Director of Enforcement copies of all pleadings filed in the Hearing Body proceeding on the motion to intervene. Within fourteen (14) days following the date the notice of appeal is filed, the Hearing Body, the Regional Entity Compliance Staff, and any other Participants in the Hearing Body proceeding, may each file a response to the notice of appeal with the NERC Director of Enforcement. Within seven (7) days following the last day for filing responses, the entity filing the notice of appeal,

and any Participant in the Hearing Body proceeding that supports the appeal, may file replies to the responses with the NERC Director of Enforcement.

4. **Disposition of Appeal** — The appeal shall be considered and decided by the Compliance Committee. The NERC Director of Enforcement shall provide copies of the notice of appeal and any responses and replies to the Compliance Committee. The Compliance Committee shall issue a written decision on the appeal; provided, that if the Compliance Committee does not issue a written decision on the appeal within forty-five (45) days following the date of filing the notice of appeal, the appeal shall be deemed denied and the decision of the Hearing Body granting or denying the motion to intervene shall stand. The NERC Director of Enforcement shall transmit copies of the Compliance Committee's decision, or shall provide notice that the forty-five (45) day period has expired with no decision by the Compliance Committee, to the Clerk, the Hearing Body, the entity filing the notice of appeal, the Regional Entity Compliance Staff, and any other Participants in the Hearing Body proceeding that filed responses to the notice of appeal or replies to responses.

5. **Appeal of Compliance Committee Decision to FERC or Other Applicable Governmental Authority** — Any entity aggrieved by the decision of the Compliance Committee on an appeal of a Hearing Body decision granting or denying a motion to intervene in a Hearing Body proceeding (including a denial of such appeal by the expiration of the forty-five (45) day period as provided in Section 414.4) may appeal or petition for review of the decision of the Compliance Committee to FERC or to another Applicable Governmental Authority having jurisdiction over the matter, in accordance with the authorities, rules and procedures of FERC or such other Applicable Governmental Authority. Any such appeal or petition for review shall be filed within the time period, if any, and in the form and manner, specified by the applicable statutes, rules or regulations governing proceedings before FERC or the other Applicable Governmental Authority.

SECTION 500 — ORGANIZATION REGISTRATION AND CERTIFICATION

501. Scope of the Organization Registration and Organization Certification Programs

The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards. Registered Entities are not and do not become Members of NERC or a Regional Entity, by virtue of being listed on the NCR. Membership in NERC is governed by Article II of NERC's Bylaws; membership in a Regional Entity or regional reliability organization is governed by that entity's bylaws or rules.

The purpose of the Organization Certification Program is to ensure that the new entity (i.e., applicant to be an RC, BA, or TOP that is not already performing the function for which it is applying to be certified as) has the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) for which it is applying thereby demonstrating the ability to become certified and then operational.

Organization Registration and Organization Certification may be delegated to Regional Entities in accordance with the procedures in this Section 500; the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into these Rules of Procedure as **Appendix 5A**; and, approved Regional Entity delegation agreements or other applicable agreements.

1. **NERC Compliance Registry** — NERC shall establish and maintain the NCR of the Bulk Power System owners, operators, and users that are subject to approved Reliability Standards.

   1.1 (a) The NCR shall set forth the identity and functions performed for each organization responsible for meeting Requirements/sub-Requirements of the Reliability Standards. Bulk Power System owners, operators, and users (i) shall provide to NERC and the applicable Regional Entity information necessary to complete the Registration, and (ii) shall provide NERC and the applicable Regional Entity with timely updates to information concerning the Registered Entity's ownership, operations, contact information, and other information that may affect the Registered Entity's Registration status or other information recorded in the Compliance Registry.

   (b) A generation or transmission cooperative, a joint-action agency or another organization may register as a Joint Registration Organization (JRO), in lieu of each of the JRO's members or related entities being registered individually for one or more functions. Refer to Section 507.

(c) Multiple entities may each register using a Coordinated Functional Registration (CFR) for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function pursuant to a written agreement for the division of compliance responsibility. Refer to Section 508.

1.2 In the development of the NCR, NERC and the Regional Entities shall determine which organizations should be placed on the NCR based on the criteria provided in the NERC *Statement of Compliance Registry Criteria* which is incorporated into these Rules of Procedure as **Appendix 5B**.

1.3 NERC and the Regional Entities shall use the following rules for establishing and maintaining the NCR based on the Registration criteria as set forth in **Appendix 5B** *Statement of Compliance Registry Criteria*:

1.3.1 NERC shall notify each organization that it is on the NCR. The Registered Entity is responsible for compliance with all the Reliability Standards applicable to the functions for which it is registered from the time it receives the Registration notification from NERC.

1.3.2 Any organization receiving such a notice may challenge its placement on the NCR according to the process in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section V.

1.3.3 The Compliance Committee of the Board of Trustees shall promptly issue a written decision on the challenge, including the reasons for the decision.

1.3.4 The decision of the Compliance Committee of the Board of Trustees shall be final unless, within 21 days of the date of the Compliance Committee of the Board of Trustees decision, the organization appeals the decision to the Applicable Governmental Authority.

1.3.5 Each Registered Entity identified on the NCR shall notify its corresponding Regional Entity(s) of any corrections, revisions, deletions, changes in ownership, corporate structure, or similar matters that affect the Registered Entity's responsibilities with respect to the Reliability Standards. Failure to notify will not relieve the Registered Entity from any responsibility to comply with the Reliability Standards or shield it from any Penalties or sanctions associated with failing to comply with the Reliability Standards applicable to its associated Registration.

1.4 For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall:

1.4.1 Ensure that all areas are under the oversight of one and only one Reliability Coordinator.

1.4.2 Ensure that all Balancing Authorities and Transmission Operator entities[2] are under the responsibility of one and only one Reliability Coordinator.

1.4.3 Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator.

1.4.4 Ensure that all Loads and generators are under the responsibility and control of one and only one Balancing Authority.

1.5 NERC shall maintain the NCR of organizations responsible for meeting the Requirements/sub-Requirements of the Reliability Standards currently in effect on its website and shall update the NCR monthly.

1.6 With respect to: (i) entities to be registered for the first time; (ii) currently-registered entities or (iii) previously-registered entities, for which registration status changes are sought, including availability and composition of a sub-set list of applicable Reliability Standards (which specifies the Reliability Standards and may specify Requirements/sub-Requirements), the registration process steps in Section III of **Appendix 5A** apply.

1.7 NERC shall establish a NERC-led, centralized review panel, comprised of a NERC lead with Regional Entity participants, in accordance with **Appendix 5A**, *Organization Registration and Organization Certification Manual*, Section III.D and **Appendix 5B**, *Statement of Compliance Registry Criteria*.

2. **Entity Certification** — NERC shall provide for Certification of all entities with primary reliability responsibilities requiring Certification. This includes those

[2] Some organizations perform the listed functions (e.g., Balancing Authority, Transmission Operator) over areas that transcend the Footprints of more than one Reliability Coordinator. Such organizations will have multiple Registrations, with each such Registration corresponding to that portion of the organization's overall area that is within the Footprint of a particular Reliability Coordinator.

entities that satisfy the criteria established in the NERC provisional Certification process. The NERC programs shall:

2.1 Evaluate and certify the competency of entities performing reliability functions. The entities presently expected to be certified include Reliability Coordinators, Transmission Operators, and Balancing Authorities.

2.2 Evaluate and certify each applicant's ability to meet the requirements for Certification.

2.3 Maintain process documentation.

2.4 Maintain records of currently certified entities.

2.5 Issue a Certification document to the applicant that successfully demonstrates its competency to perform the evaluated functions.

3. **Delegation and Oversight**

3.1 NERC may delegate responsibilities for Organization Registration and Organization Certification to Regional Entities in accordance with requirements established by NERC. Delegation will be via the delegation agreement between NERC and the Regional Entity or other applicable agreement. The Regional Entity shall administer Organization Registration and Organization Certification Programs in accordance with such delegations to meet NERC's programs goals and requirements subject to NERC oversight.

3.2 NERC shall develop and maintain a plan to ensure the continuity of Organization Registration and Organization Certification within the geographic or electrical boundaries of a Regional Entity in the event that no entity is functioning as a Regional Entity for that Region, or the Regional Entity withdraws as a Regional Entity, or does not operate its Organization Registration and Organization Certification Programs in accordance with delegation agreements.

3.3 NERC shall develop and maintain a program to monitor and oversee the NERC Organization Registration and Organization Certification Programs activities that are delegated to each Regional Entity through a delegation agreement or other applicable agreement.

3.3.1 This program shall monitor whether the Regional Entity carries out those delegated activities in accordance with NERC requirements, and whether there is consistency, fairness of administration, and comparability.

3.3.2 Monitoring and oversight shall be accomplished through direct participation in the Organization Registration and Organization Certification Programs with periodic reviews of documents and records of both programs.

502. Organization Registration and Organization Certification Program Requirements

1. NERC shall maintain the Organization Registration and Organization Certification Programs.

   1.1 The roles and authority of Regional Entities in the programs are delegated from NERC pursuant to the Rules of Procedure through regional delegation agreements or other applicable agreements.

   1.2 Processes for the programs shall be administered by NERC and the Regional Entities. Materials that each Regional Entity uses are subject to review and approval by NERC.

   1.3 The appeals process for the Organization Registration and Organization Certification Programs are identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Sections V and VI, respectively.

   1.4 The Certification Team membership is identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section IV.8.d.

2. To ensure consistency and fairness of the Organization Registration and Organization Certification Programs, NERC shall develop procedures to be used by all Regional Entities and NERC in accordance with the following criteria:

   2.1 NERC and the Regional Entities shall have data management processes and procedures that provide for confidentiality, integrity, and retention of data and information collected.

   2.2 Documentation used to substantiate the conclusions of the Regional Entity/ NERC related to Registration and/or Certification must be retained by the Regional Entity for (6) six years, unless a different retention period is otherwise identified, for the purposes of future audits of these programs.

   2.3 To maintain the integrity of the NERC Organization Registration and Organization Certification Programs, NERC, Regional Entities, Certification Team members, program audit team members (Section 506), and committee members shall maintain the confidentiality of information provided by an applicant or entities.

      2.2.1 NERC and the Regional Entities shall have appropriate codes of conduct and confidentiality agreements for staff, Certification

Team, Certification related committees, and Certification program audit team members.

2.2.2 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall maintain the confidentiality of any Registration or Certification-related discussions or documents designated as confidential (see Section 1500 for types of Confidential Information).

2.2.3 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall treat as confidential the individual comments expressed during evaluations, program audits and report-drafting sessions.

2.2.4 Copies of notes, draft reports, and other interim documents developed or used during an entity Certification evaluation or program audit shall be destroyed after the public posting of a final, uncontested report.

2.2.5 Information deemed by an applicant, entity, a Regional Entity, or NERC as confidential, including Critical Energy Infrastructure Information, shall not be released publicly or distributed outside of a committee or team.

2.2.6 In the event that an individual violates any of the confidentiality rules set forth above, that individual and any member organization with which the individual is associated will be subject to immediate dismissal from the audit team and may be prohibited from future participation in Compliance Monitoring and Enforcement Program activities by the Regional Entity or NERC.

2.2.7 NERC shall develop and provide training in auditing skills to all individuals prior to their participation in Certification evaluations. Training for Certification Team leaders shall be more comprehensive than the training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

2.4 An applicant that is determined to be competent to perform a function after completing all Certification requirements shall be deemed certified by NERC to perform that function for which it has demonstrated full competency.

2.4.1 All NERC certified entities shall be included on the NCR.

503. Regional Entity Implementation of Organization Registration and Organization Certification Program Requirements

1. **Delegation** — Recognizing the Regional Entity's knowledge of and experience with their members, NERC may delegate responsibility for Organization Registration and Organization Certification to the Regional Entity through a delegation agreement.

2. **Registration** — The following Organization Registration activities shall be managed by the Regional Entity per the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into the Rules of Procedure as Appendix 5A *Organization Registration and Organization Certification Manual*:

   2.1 Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4).

3. **Certification —** The following Organization Certification activities shall be managed by the Regional Entity in accordance with an approved delegation agreement or another applicable agreement:

   3.1 An entity seeking Certification to perform one of the functions requiring Certification shall contact the Regional Entity for the Region(s) in which it plans to operate to apply for Certification.

   3.2 An entity seeking Certification and other affected entities shall provide all information and data requested by NERC or the Regional Entity to conduct the Certification process.

   3.3 Regional Entities shall notify NERC of all Certification applicants.

   3.4 NERC and/or the Regional Entity shall evaluate the competency of entities requiring Certification to meet the NERC Certification requirements.

   3.5 NERC or the Regional Entity shall establish Certification procedures to include evaluation processes, schedules and deadlines, expectations of the applicants and all entities participating in the evaluation and Certification processes, and requirements for Certification Team members.

      3.5.1 The NERC / Regional Entity Certification procedures will include provisions for on-site visits to the applicant's facilities to review the data collected through questionnaires, interviewing the operations and management personnel, inspecting the facilities and equipment (including requesting a demonstration of all tools identified in the Certification process), reviewing all necessary documents and data (including all agreements, processes, and procedures identified in the Certification process), reviewing

Certification documents and projected system operator work schedules, and reviewing any additional documentation needed to support the completed questionnaire or inquiries arising during the site visit.

3.5.2 The NERC/ Regional Entity Certification procedures will provide for preparation of a written report by the Certification Team, detailing any deficiencies that must be resolved prior to granting Certification, along with any other recommendations for consideration by the applicant, the Regional Entity, or NERC.

504. Appeals

1. NERC shall maintain an appeals process to resolve any disputes related to Registration or Certification activities per the *Organization Registration and Organization Certification Manual,* which is incorporated in these Rules of Procedure as Appendix 5A.

2. The Regional Entity Certification appeals process shall culminate with the Regional Entity board or a committee established by and reporting to the Regional Entity board as the final adjudicator, provided that where applicable, Canadian provincial governmental authorities may act as the final adjudicator in their jurisdictions. NERC shall be notified of all appeals and may observe any proceedings **(Appendix 5A** *Organization Registration and Organization Certification Manual*).

505. Program Maintenance

NERC shall maintain its program materials, including such manuals or other documents as it deems necessary, of the governing policies and procedures of the Organization Registration and Organization Certification Programs.

506. Independent Audit of NERC Organization Registration and Organization Certification Program

1. NERC, through the Compliance and Certification Committee, shall provide for an independent audit of its Organization Registration and Organization Certification Programs at least once every three years, or more frequently, as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board.

2. The audit shall evaluate the success, effectiveness and consistency of the NERC Organization Registration and Organization Certification Programs.

3. The final report shall be posted by NERC for public viewing.

4. If the audit report includes recommendations to improve the program, the administrators of the program shall provide a written response to the Board within 30 days of the final report, detailing the disposition of each and every

recommendation, including an explanation of the reasons for rejecting a recommendation and an implementation plan for the recommendations accepted.

507. Provisions Relating to Joint Registration Organizations (JRO)

1. In addition to registering as the entity responsible for all functions that it performs itself, an entity may register as a JRO on behalf of one or more of its members or related entities for one or more functions for which such members or related entities would otherwise be required to register and, thereby, accept on behalf of such members or related entities all compliance responsibility for that function or those functions including all reporting requirements. Any entity seeking to register as a JRO must submit a written agreement with its members or related entities for all Requirements/sub-Requirements for the function(s) for which the entity is registering for and takes responsibility for, which would otherwise be the responsibility of one or more of its members or related entities. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the JRO Registration.

2. The JRO Registration data must include the same Registration information as a normal compliance Registration entry. The JRO is responsible for providing all of the information and data, including submitting reports, as needed by the Regional Entity for performing assessments of compliance.

3. The Regional Entity shall notify NERC of each JRO that the Regional Entity accepts. The notification will identify the point of contact and the functions(s) being registered for on behalf of its members or related entities.

4. For purposes of Compliance Audits, the Regional Entity shall keep a list of all JROs. This document shall contain a list of each JRO's members or related entities and the function(s) for which the JRO is registered for that member(s) or related entity(s). It is the responsibility of the JRO to provide the Regional Entity with this information as well as the applicable JRO agreement(s).

5. The Regional Entity may request clarification of any list submitted to it that identifies the members of the JRO and may request such additional information as the Regional Entity deems appropriate.

6. The Regional Entity's acceptance of a JRO shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded the JRO will meet the Registration requirements of Section 501(1.4).

7. NERC shall maintain, and post on its website, a JRO registry listing all JRO Registrations that have been reviewed and accepted by the Regional Entity. The posting shall identify the JRO entity taking compliance responsibilities for itself and its members.

8. The JRO shall inform the Regional Entity of any changes to an existing JRO. The Regional Entity shall promptly notify NERC of each such revision.

9. Nothing in Section 507 shall preclude a member of a JRO, a related entity, or any other entity from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards applicable to the function(s) for which the member or other entity is registering. A JRO member or related entity that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the JRO of its Registration.

508. Provisions Relating to Coordinated Functional Registration (CFR) Entities

1. In addition to registering as an entity responsible for all functions that it performs itself, multiple entities may each register using a CFR for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function. The CFR submission must include a written agreement that governs itself and clearly specifies the entities' respective compliance responsibilities. The Registration of the CFR is the complete Registration for each entity. Additionally, each entity shall take full compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements it has registered for in the CFR. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the CFR.

2. Each CFR or each individual entity within a CFR must identify a point of contact that is responsible for providing information and data, including submitting reports as needed by the Regional Entity related to the CFR Registration.

3. The Regional Entity shall notify NERC of each CFR that the Regional Entity accepts.

4. NERC or the Regional Entity may request clarification of any list submitted to it that identifies the compliance responsibilities of the CFR and may request such additional information as NERC or the Regional Entity deems appropriate.

5. The Regional Entity's acceptance of that CFR shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded the CFR will meet the Registration requirements of Section 501(1.4).

6. NERC shall maintain, and post on its website, a CFR registry listing all CFR Registrations that have been accepted by NERC or by a Regional Entity. The posting shall clearly list all the Reliability Standards or Requirements/sub-Requirements thereof for which each entity of the CFR is responsible for under the CFR.

7. The point of contact shall inform the Regional Entity of any changes to an existing CFR. The Regional Entity shall promptly notify NERC of each such revision.

8. In the event of a violation of a Reliability Standard or of a Requirement/sub-Requirement of a Reliability Standard for which an entity of a CFR is registered, that entity shall be identified in the Notice of Alleged Violation and shall be assessed the sanction or Penalty in accordance with the NERC Sanctions Guidelines. In the event a Regional Entity is not able to determine which entity(ies) is responsible for a particular Reliability Standard, or Requirements/sub-Requirements thereof that has been violated, the Regional Entity shall investigate the noncompliance in accordance with the NERC Rules of Procedure Section 400, *Compliance Enforcement*, to determine the entity(ies) to which the Regional Entity shall to issue the sanction or Penalty for the violation.

9. Nothing in Section 508 shall preclude an entity registered in a CFR, or any other entity from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards applicable to the function(s) for which the entity is registering. An entity registered in a CFR that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the point of contact of its Registration.

509. Exceptions to the Definition of the Bulk Electric System

An Element is considered to be (or not be) part of the Bulk Electric System by applying the BES Definition to the Element (including the inclusions and exclusions set forth therein). Appendix 5C sets forth the procedures by which (i) an entity may request a determination that an Element that falls within the definition of the Bulk Electric System should be exempted from being considered a part of the Bulk Electric System, or (ii) an entity may request that an Element that falls outside of the definition of the Bulk Electric System should be considered part of the Bulk Electric System.

SECTION 600 — PERSONNEL CERTIFICATION PROGRAM

601. Scope of Personnel Certification Program

Maintaining the reliability of the Bulk Power System through implementation of the Reliability Standards requires skilled, and qualified personnel, including system operators. NERC shall develop a Personnel Certification Program to:

1. Provide the mechanism to determine system operators' essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations;

2. administer a system operator Certification exam; and

3. award the system operator Certification Credential to individuals who pass the exam.

The NERC Personnel Certification Program shall be international in scope consistent with the ERO's international regulatory responsibility for the reliability of the Bulk Power System in North America.

NERC Reliability Standards define which system operators require certification pursuant to the NERC Personnel Certification Program.

The NERC Personnel Certification Governance Committee (PCGC) is the governing body that establishes the policies, sets fees, and monitors the performance of the Personnel Certification Program for system operators.

602. Structure of ERO Personnel Certification Program

The PCGC shall develop and update, as necessary, a manual which describes the following:

1. requirements for administering the system operator examinations;

2. requirements for exam eligibility;

3. requirements for awarding the Certification Credential;

4. requirements for Certification Credential maintenance;

5. dispute resolution procedures; and

6. disciplinary~~displicinary~~ action guidelines.

603. Examination and Maintenance of NERC System Operator Certification Credentials

1. System operators seeking to obtain a Credential must pass an examination to earn the Credential.

2. A certificate will be issued to successful candidates which is valid for three years.

3. A system operator must earn Continuing Education Hours (CE Hours) in NERC-Approved Learning Activities within the three-year period preceding the expiration date of his/her certificate as determined by the PCGC and posted in the NERC System Operator Program Manual. A system operator must request a renewal and submit the appropriate fee for Certification renewal evaluation.

4. The Credential of a certified system operator who does not accumulate the required number and balance of CE Hours within the three-year period will be Suspended. A system operator with a Suspended certificate cannot perform any task that requires an operator to be NERC-certified. The system operator with a Suspended Credential will have up to twelve months to acquire the necessary CE Hours.

   4.1 During the time of suspension, the original anniversary date will be maintained. Therefore, should the system operator accumulate the required number of CE Hours within the twelve month suspension period, he/she will be issued a certificate that will be valid for three years from the previous expiration date.

   4.2 At the end of the twelve-month suspension period, if the system operator has not accumulated the required number of CE Hours, the Credential will be Revoked and all CE Hours earned will be forfeited. After a Credential is Revoked, the system operator will be required to pass an examination to become certified.

5. Hardship: Due to unforeseen events and extenuating circumstances, a certified system operator may be unable to accumulate the necessary CE Hours in the time frame required by the Personnel Certification Program to maintain the Credential. In such an event, the individual must submit a written request containing a thorough explanation of the circumstances and supporting information to the NERC Personnel Certification Manager. The PCGC retains the right to invoke this hardship clause as it deems appropriate to address such events or circumstances.

604. Dispute Resolution Process

1. Any dispute arising under the NERC agreement establishing the *NERC Personnel Certification Program* or from the establishment of any NERC rules, policies, or procedures dealing with any segment of the Certification process shall be subject to the NERC System Operator Certification Dispute Resolution Process. The Dispute Resolution Process is for the use of persons who hold an operator Certification or persons wishing to be certified to dispute the validity of the examination, the content of the test, the content outlines, or the Registration process.

2. Dispute Resolution Process consists of three steps.

2.1. Notify NERC Personnel Certification Program Staff: This first step can usually resolve the issues without further actions. It is expected that most disputes will be resolved at this step. If the issue(s) is not resolved to the satisfaction of the parties involved in the first step, the issue can be brought to the PCGC Dispute Resolution Task Force.

2.2. PCGC Dispute Resolution Task Force: If the NERC staff did not resolve the issue(s) to the satisfaction of the parties involved, a written request must be submitted to the chairman of the PCGC through NERC staff explaining the issue(s) and requesting further action. Upon receipt of the letter, the PCGC chairman will present the request to the PCGC Dispute Resolution Task Force for action. This task force consists of three current members of the PCGC. The PCGC Dispute Resolution Task Force will investigate and consider the issue(s) presented and make a decision. This decision will then be communicated to the submitting party, the PCGC chairman, and the NERC staff within 45 calendar days of receipt of the request.

3. Personnel Certification Governance Committee: If the PCGC Dispute Resolution Task Force's decision did not resolve the issue(s) to the satisfaction of the parties involved, the final step in the process is for the issue(s) to be brought before the PCGC. Within 45 days of the date of the Task Force's decision, the disputing party shall submit a written request to the PCGC chairman through NERC staff requesting that the issue(s) be brought before the PCGC for resolution. The chairman shall see that the necessary documents and related data are provided to the PCGC members as soon as practicable. The PCGC will then meet or conference to discuss the issue(s) and make their decision within 60 calendar days of the chairman's receipt of the request. The decision will be provided to the person bringing the issue(s) and the NERC staff. The PCGC is the governing body of the Certification program and its decision is final.

4. Dispute Resolution Process Expenses: All individual expenses associated with the Dispute Resolution Process, including salaries, meetings, or consultant fees, shall be the responsibility of the individual parties incurring the expense.

5. Decision Process: Robert's Rules of Order shall be used as a standard of conduct for the Dispute Resolution Process. A majority vote of the members present will decide all issues. The vote will be taken in a closed session. No member of the PCGC may participate in the Dispute Resolution Process, other than as a party or witness, if he or she has an interest in the particular matter.

5.1 A stipulation of invoking the Dispute Resolution Process is that the entity invoking the Dispute Resolution Process agrees that neither NERC (its members, Board of Trustees, committees, subcommittees, and staff), any person assisting in the Dispute Resolution Process, nor any company employing a person assisting in the Dispute Resolution Process, shall be liable, and they shall be held harmless against the consequences of or any

action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the Dispute Resolution Process. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

605. Disciplinary Action

1. Disciplinary action may be necessary to protect the integrity of the system operator Credential. The PCGC may initiate disciplinary action should an individual act in a manner that is inconsistent with expectations, including but not limited to:

   1.1. Willful, gross, and/or repeated violation of the NERC Reliability Standards as determined by a NERC investigation.

   1.2. Willful, gross, and/or repeated negligence in performing the duties of a certified system operator as determined by a NERC investigation.

   1.3. Intentional misrepresentation of information provided on a NERC application for a system operator Certification exam or to maintain a system operator Credential using CE Hours.

   1.4. Intentional misrepresentation of identification in the exam process, including a person identifying himself or herself as another person to obtain Certification for the other person.

   1.5. Any form of cheating during a Certification exam, including, but not limited to, bringing unauthorized reference material in the form of notes, crib sheets, or other methods of cheating into the testing center.

   1.6. A certified system operator's admission to or conviction of any felony or misdemeanor directly related to his/her duties as a system operator.

2. Hearing Process: Upon report to NERC of a candidate's or certified system operator's alleged misconduct, the NERC PCGC Credential Review Task Force will convene for the determination of facts. An individual, government agency, or other investigating authority can file a report. Unless the Task Force initially determines that the report of alleged misconduct is without merit, the candidate or certified system operator will be given the right to notice of the allegation. A hearing will be held and the charged candidate or certified system operator will be given an opportunity to be heard and present further relevant information. The Task Force may seek out information from other involved parties. The hearing will not be open to the public, but it will be open to the charged candidate or certified system operator and his or her representative. The Task Force will deliberate in a closed session, but the Task Force cannot receive any evidence during the closed session that was not developed during the course of the hearing.

3. Task Force's decision: The Task Force's decision will be unanimous and will be in writing with inclusion of the facts and reasons for the decision. The Task Force's written decision will be delivered to the PCGC and by certified post to the charged candidate or certified system operator. In the event that the Task Force is unable to reach a unanimous decision, the matter shall be brought to the full committee for a decision.

   3.1. No Action: Allegation of misconduct was determined to be unsubstantiated or inconsequential to the Credential.

   3.2. Probation: A letter will be sent from NERC to the offender specifying:

      3.2.1. The length of time of the probationary period (to be determined by the PCGC).

      3.2.2. Credential will remain valid during the probationary period.

      3.2.3. The probationary period does not affect the expiration date of the current certificate.

      3.2.4. During the probationary period, a subsequent offense of misconduct, as determined through the same process as described above, may be cause for more serious consequences.

   3.3. Revoke for Cause: A letter will be sent from NERC to the offender specifying:

      3.3.1. The length of time of the probationary period (to be determined by the PCGC).

      3.3.2. Credential is no longer valid.

      3.3.3. Successfully passing an exam will be required to become recertified.

      3.3.4. An exam will not be authorized until the revocation period expires

   3.4. Termination of Credential: A letter will be sent from NERC to the offender specifying permanent removal of Credential.

4. Credential Review Task Force: The Credential Review Task Force shall be comprised of three active members of the PCGC assigned by the Chairman of the PCGC on an ad hoc basis. No one on the Credential Review Task Force may have an interest in the particular matter. The Task Force will meet in a venue determined by the Task Force chairman.

5. Appeal Process: The decision of the Task Force may be appealed using the NERC System Operator Certification Dispute Resolution Process.

606. Candidate Testing

1. The PCGC shall develop exams to evaluate individual competence in a manner that is objective, and fair to all candidates, and to determine essential knowledge relating to NERC Reliability Standards as well as principles of the Bulk Power System operations.

2. The PCGC shall oversee exam administration as follows:

   2.1 Adopt and implement a formal policy of periodic review of exams to assess~~access~~ ongoing relevance to knowledge and skill needed in the discipline; and

   2.2 Conduct ongoing studies to substantiate the reliability and validity of exams.

3. The PCGC shall develop and utilize policies and procedures to ensure the integrity and security of exams and the transparency of test administration consistent with the following:

   3.1 The PCGC shall establish pass/fail levels that protect the public with a method that is based on competence and generally accepted standards in the psychometric community as being fair and reasonable;

   3.2 The PCGC shall conduct ongoing studies to substantiate the reliability and validity of the exams;

   3.3 The PCGC shall dictate how long examination records are kept in their original format; and

   3.4 The PCGC shall demonstrate that different revisions of the exams assess equivalent content.

607. Public Information About the Personnel Certification Program

The PCGC shall maintain and publish the following:

1. a summary of the information, knowledge, or functions covered by each examination administered pursuant to the Personnel Certification Program; and

2. an annual summary of Certification activities for the Personnel Certification Program, including, the number of examinations delivered, the number of applicants who passed, the number of applicants who failed, and the number of applicants certified.

608. Responsibilities to Applicants for Certification or Re-Certification

The PCGC shall adhere to the following with respect to personnel applicants:

1. comply with all requirements of applicable federal and state/provincial laws with respect to all Certification and re-Certification activities, and shall require compliance of all contractors and/or providers of services;

2. make available to all applicants copies of formalized procedures for application for, and attainment of, personnel Certification and re-Certification and shall uniformly follow and enforce such procedures for all applicants;

3. implement a formal policy for the periodic review of eligibility criteria and application procedures for fairness;

4. provide competently proctored examination sites; and

5. uniformly provide applicants with examination results and give content summary after the examination.

609. Responsibilities to Employers of Certified Personnel

The PCGC shall adhere to the following with respect to certified personnel:

1. demonstrate that the exams adequately measure essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations;

2. award Certification and re-Certification only after the skill and knowledge of the individual have been evaluated and determined to be acceptable;

3. maintain, in an electronic format, a current list of those personnel certified in the programs and have policies and procedures that delineate what information about a Certification Credential holder may be made public and under what circumstances; and

4. develop formal policies and procedures for discipline of a Certification Credential holder, including the revocation of the certificate, for conduct deemed harmful to the public or inappropriate to the discipline (e.g., incompetence, unethical behavior, physical or mental impairment affecting performance). These procedures shall incorporate due process.

SECTION 700 — RELIABILITY READINESS EVALUATION AND IMPROVEMENT AND FORMATION OF SECTOR FORUMS

701. Confidentiality Requirements for Readiness Evaluations and Evaluation Team Members

1. All information made available or created during the course of any reliability readiness evaluation including, but not limited to, data, Documents, observations and notes, shall be maintained as confidential by all evaluation team members, in accordance with the requirements of Section 1500.

2. Evaluation team members are obligated to destroy all confidential evaluation notes following the posting of the final report of the reliability readiness evaluation.

3. NERC will retain reliability readiness evaluation-related documentation, notes, and materials for a period of time as defined by NERC.

4. These confidentiality requirements shall survive the termination of the NERC Reliability Readiness Evaluation and Improvement Program.

702. Formation of Sector Forum

1. NERC will form a sector forum at the request of any five members of NERC that share a common interest in the safety and reliability of the Bulk Power System. The members of sector forum may invite such others of the members of NERC to join the sector forum as the sector forum deems appropriate.

2. The request to form a sector forum must include a proposed charter for the sector forum. The Board must approve the charter.

3. NERC will provide notification of the formation of a sector forum to its membership roster. Notices and agendas of meetings shall be posted on NERC's website.

4. A sector forum may make recommendations to any of the NERC committees and may submit a Standards Authorization Request to the NERC *Reliability Standards Development Procedure*.

SECTION 800 — RELIABILITY ASSESSMENT AND PERFORMANCE ANALYSIS

801. Objectives of the Reliability Assessment and Performance Analysis Program

The objectives of the NERC Reliability Assessment and Performance Analysis Program are to: (1) conduct, and report the results of, an independent assessment of the overall reliability and adequacy of the interconnected North American Bulk Power Systems, both as existing and as planned; (2) analyze off-normal events on the Bulk Power System; (3) identify the root causes of events that may be precursors of potentially more serious events; (4) assess past reliability performance for lessons learned; (5) disseminate findings and lessons learned to the electric industry to improve reliability performance; and (6) develop reliability performance benchmarks. The final reliability assessment reports shall be approved by the Board for publication to the electric industry and the general public.

802. Scope of the Reliability Assessment Program

1. The scope of the Reliability Assessment Program shall include:

    1.1 Review, assess, and report on the overall electric generation and transmission reliability (adequacy and operating reliability) of the interconnected Bulk Power Systems, both existing and as planned.

    1.2 Assess and report on the key issues, risks, and uncertainties that affect or have the potential to affect the reliability of existing and future electric supply and transmission.

    1.3 Review, analyze, and report on Regional Entity self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.

    1.4 Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on Bulk Power System reliability.

    1.5 Investigate, assess, and report on the potential impacts of new and evolving electricity market practices, new or proposed regulatory procedures, and new or proposed legislation (e.g. environmental requirements) on the adequacy and operating reliability of the Bulk Power Systems.

2. The Reliability Assessment Program shall be performed in a manner consistent with the Reliability Standards of NERC including but not limited to those that specify reliability assessment Requirements.

803. Reliability Assessment Reports

The number and type of periodic assessments that are to be conducted shall be at the discretion of NERC. The results of the reliability assessments shall be documented in three reports: the long-term and the annual seasonal (summer) and the annual seasonal (winter) assessment reports. NERC shall also conduct special reliability assessments from time to time as circumstances warrant. The reliability assessment reports shall be reviewed and approved for publication by the Board. The three regular reports are described below.

1. **Long-Term Reliability Assessment Report** — The annual long-term report shall cover a ten-year planning horizon. The planning horizon of the long-term reliability assessment report shall be subject to change at the discretion of NERC. Detailed generation and transmission adequacy assessments shall be conducted for the first five years of the review period. For the second five years of the review period, the assessment shall focus on the identification, analysis, and projection of trends in peak demand, electric supply, and transmission adequacy, as well as other industry trends and developments that may impact future electric system reliability. Reliability issues of concern and their potential impacts shall be presented along with any mitigation plans or alternatives. The long-term reliability assessment reports will generally be published in the fall (September) of each year. NERC will also publish electricity supply and demand data associated with the long-term reliability assessment report.

2. **Summer Assessment Report** — The annual summer seasonal assessment report typically shall cover the four-month (June–September) summer period. It shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected summer peak demands. It shall also identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may include possible mitigation alternatives. The report will generally be published in mid-May for the upcoming summer period.

3. **Winter Assessment Report** — The annual winter seasonal assessment report shall cover the three-month (December–February) winter period. The report shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected winter peak demands. Similar to the summer assessment, the winter assessment shall identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may also include possible mitigation alternatives. The winter assessment report will generally be published in mid-November for the upcoming winter period.

4. **Special Reliability Assessment Reports** — In addition to the long-term and seasonal reliability assessment reports, NERC shall also conduct special reliability assessments on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the Board or governmental authorities. The teams of reliability and technical experts also may initiate special assessments of key

reliability issues and their impacts on the reliability of a regions, subregions, or Interconnection (or a portion thereof). Such special reliability assessments may include, among other things, operational reliability assessments, evaluations of emergency response preparedness, adequacy of fuel supply, hydro conditions, reliability impacts of new or proposed environmental rules and regulations, and reliability impacts of new or proposed legislation that affects or has the potential to affect the reliability of the interconnected Bulk Power Systems in North America.

804. Reliability Assessment Data and Information Requirements

To carry out the reviews and assessments of the overall reliability of the interconnected Bulk Power Systems, the Regional Entities and other entities shall provide sufficient data and other information requested by NERC in support of the annual long-term and seasonal assessments and any special reliability assessments.

Some of the data provided for these reviews and assessment may be considered confidential from a competitive marketing perspective, a Critical Energy Infrastructure Information perspective, or for other purposes. Such data shall be treated in accordance with the provisions of Section 1500 – Confidential Information.

While the major sources of data and information for this program are the Regional Entities, a team of reliability and technical experts is responsible for developing and formulating its own independent conclusions about the near-term and long-term reliability of the Bulk Power Systems.

In connection with the reliability assessment reports, requests shall be submitted to each of the Regional Entities for required reliability assessment data and other information, and for each Regional Entity's self-assessment report. The timing of the requests will be governed by the schedule for the preparation of the assessment reports.

The Regional Entity self-assessments are to be conducted in compliance with NERC Reliability Standards and the respective regional planning criteria. The team(s) of reliability and technical experts shall also conduct interviews with the Regional Entities as needed. The summary of the Regional Entity self-assessments that are to be included in the assessment reports shall follow the general outline identified in NERC's request. This outline may change from time to time as key reliability issues change.

In general, the Regional Entity reliability self-assessments shall address, among other areas, the following topics: demand and Net Energy for Load; assessment of projected resource adequacy; any transmission constraints that may impact bulk transmission adequacy and plans to alleviate those constraints; any unusual operating conditions that could impact reliability for the assessment period; fuel supply adequacy; the deliverability of generation (both internal and external) to Load; and any other reliability issues in the Region and their potential impacts on the reliability of the Bulk Power Systems.

805. Reliability Assessment Process

Based on their expertise, the review of the collected data, the review of the Regional Entity self-assessment reports, and interviews with the Regional Entities, as appropriate, the teams of reliability and technical experts shall perform an independent review and assessment of the generation and transmission adequacy of each Region's existing and planned Bulk Power System. The results of the review teams shall form the basis of NERC's long-term and seasonal reliability assessment reports. The review and assessment process is briefly summarized below.

1. **Resource Adequacy Assessment** — The teams shall evaluate the regional demand and resource capacity data for completeness in the context of the overall resource capacity needs of the Region. The team shall independently evaluate the ability of the Regional Entity members to serve their obligations given the demand growth projections, the amount of existing and planned capacity, including committed and uncommitted capacity, contracted capacity, or capacity outside of the Region. If the Region relies on capacity from outside of the Region to meet its resource objectives, the ability to deliver that capacity shall be factored into the assessment. The demand and resource capacity information shall be compared to the resource adequacy requirements of the Regional Entity for the year(s) or season(s) being assessed. The assessment shall determine if the resource information submitted represents a reasonable and attainable plan for the Regional Entity and its members. For cases of inadequate capacity or reserve margin, the Regional Entity will be requested to analyze and explain any resource capacity inadequacies and its plans to mitigate the reliability impact of the potential inadequacies. The analysis may be expanded to include surrounding areas. If the expanded analysis indicates further inadequacies, then an interregional problem may exist and will be explored with the applicable Regions. The results of these analyses shall be described in the assessment report.

2. **Transmission Adequacy and Operating Reliability Assessment** — The teams shall evaluate transmission system information that relates to the adequacy and operating reliability of the regional transmission system. That information shall include: regional planning study reports, interregional planning study reports, and/or regional operational study reports. If additional information is required, another data request shall be sent to the Regional Entity. The assessment shall provide a judgment on the ability of the regional transmission system to operate reliably under the expected range of operating conditions over the assessment period as required by NERC Reliability Standards. If sub-areas of the regional system are especially critical to the Reliable Operation of the regional bulk transmission system, these Facilities or sub-areas shall be reviewed and addressed in the assessment. Any areas of concern related to the adequacy or operating reliability of the system shall be identified and reported in the assessment.

3. **Seasonal Operating Reliability Assessment** — The team(s) shall evaluate the overall operating reliability of the regional bulk transmission systems. In areas with potential resource adequacy or system operating reliability problems,

operational readiness of the affected Regional Entities for the upcoming season shall be reviewed and analyzed. The assessment may consider unusual but possible operating scenarios and how the system is expected to perform. Operating reliability shall take into account a wide range of activities, all of which should reinforce the Regional Entity's ability to deal with the situations that might occur during the upcoming season. Typical activities in the assessment may include: facility modifications and additions, new or modified operating procedures, emergency procedures enhancement, and planning and operating studies. The teams shall report the overall seasonal operating reliability of the regional transmission systems in the annual summer and winter assessment reports.

4. **Reporting of Reliability Assessment Results** — The teams of reliability and technical experts shall provide an independent assessment of the reliability of the Regional Entities and the North American interconnected Bulk Power System for the period of the assessment. While the Regional Entities are relied upon to provide the information to perform such assessments, the review team is not required to accept the conclusions provided by the Regional Entities. Instead, the review team is expected, based on their expertise, to reach their own independent conclusions about the status of the adequacy of the generation and bulk power transmission systems of North America.

   The review team also shall strive to achieve consensus in their assessments. The assessments that are made are based on the best information available at the time. However, since judgment is applied to this information, legitimate differences of opinion can develop. Despite these differences, the review team shall work to achieve consensus on their findings.

   In addition to providing long-term and seasonal assessments in connection with the Reliability Assessment Program, the review team of experts shall also be responsible for recommending new and revised Reliability Standards related to the reliability assessments and the reliability of the Bulk Power Systems. These proposals for new or revised Reliability Standards shall be entered into NERC's Reliability Standards development process.

   Upon completion of the assessment, the team shall share the results with the Regional Entities. The Regional Entities shall be given the opportunity to review and comment on the conclusions in the assessment and to provide additional information as appropriate. The reliability assessments and their conclusions are the responsibility of NERC's technical review team and NERC.

   The preparation and approval of NERC's reliability assessment reports shall follow a prescribed schedule including review, comment, and possible approval by appropriate NERC committees. The long-term and seasonal (summer and winter) reliability assessment reports shall be further reviewed for approval by the Board for publication to the electric industry.

806. Scope of the Reliability Performance and Analysis Program

The components of the program will include analysis of large-scale outages, disturbances, and near misses to determine root causes and lessons learned; identification and continuous monitoring of performance indices to detect emerging trends and signs of a decline in reliability performance; and communications of performance results, trends, recommendations, and initiatives to those responsible to take actions; followed with confirmation of actions to correct any deficiencies identified. Within NERC, the reliability performance program will provide performance results to the Reliability Standards Development and Compliance Monitoring and Enforcement Programs to make the necessary adjustments to preserve reliability based on a risk-based approach.

807. Analysis of Major Events

Responding to major events affecting the Bulk Power System such as significant losses of Load or generation, significant Bulk Power System disturbances, or other emergencies on the Bulk Power System, can be divided into four phases: situational assessment and communications; situation tracking and communications; data collection, investigation, analysis, and reporting; and follow-up on recommendations.

1. NERC's role following a major event is to provide leadership, coordination, technical expertise, and assistance to the industry in responding to the major event. Working closely with the Regional Entities and Reliability Coordinators, and other appropriate Registered Entities, NERC will coordinate and facilitate efforts among industry participants, and with state, federal, and provincial governments in the United States and Canada to support the industry's response.

2. When responding to any major event where physical or cyber security is suspected as a cause or contributing factor to the major event, NERC will immediately notify appropriate government agencies and coordinate its activities with them.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator of the Bulk Power System shall also provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entity as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

4. During the conduct of NERC analyses, assistance may be needed from government agencies. This assistance could include: authority to require data reporting from affected or involved parties; communications with other agencies of government; investigations related to possible criminal or terrorist involvement in the major event; resources for initial data gathering immediately after the major

event; authority to call meetings of affected or involved parties; and technical and analytical resources for studies.

5. NERC shall work with all other participants to establish a clear delineation of roles, responsibilities, and coordination requirements among industry and government for the investigation and reporting of findings, conclusions, and recommendations related to major events with the objective of avoiding, to the extent possible, multiple investigations of the same major event. If the major event is confined to a single Regional Entity, NERC representatives will participate as members of the Regional Entity analysis team. NERC will establish, maintain, and revise from time to time as appropriate based on experience, a manual setting forth procedures and protocols for communications and sharing and exchange of information between and among NERC, the affected Regional Entity or Entities, and relevant governmental authorities, industry organizations and Bulk Power System user, owners, and operators concerning the investigation and analysis of major events.

6. NERC and applicable entity(s) will apply, as appropriate to the circumstances of the major event, the NERC *Blackout and Disturbance Response Procedures*, which are incorporated into these Rules of Procedure as **Appendix 8**. These procedures provide a framework to guide NERC's response to major events that may have multiregional, national, or international implications. Experienced industry leadership shall be applied to tailor the response to the specific circumstances of the major event. In accordance with those procedures, the NERC president will determine whether the major event warrants analysis at the NERC level. A Regional Entity may request that NERC elevate any analysis of a major event to the NERC level.

7. NERC will screen and analyze the findings and recommendations from the analysis, and those with generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

808. Analysis of Off-Normal Occurrences, Bulk Power System Performance, and Bulk Power System Vulnerabilities

1. NERC and Regional Entities will analyze Bulk Power System and equipment performance occurrences that do not rise to the level of a major event, as described in Section 807. NERC and Regional Entities will also analyze potential vulnerabilities in the Bulk Power System that they discover or that are brought to their attention by other sources including government agencies. The purpose of these analyses is to identify the root causes of occurrences or conditions that may be precursors of major events or other potentially more serious occurrences, or that have the potential to cause major events or other more serious occurrences, to assess past reliability performance for lessons learned, and to develop reliability performance benchmarks and trends.

2. NERC and Regional Entities will screen and analyze off-normal occurrences, Bulk Power System performance, and potential Bulk Power System vulnerabilities for significance, and information from those indicated as having generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator, of the Bulk Power System shall provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entities as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

809. Reliability Benchmarking

NERC shall identify and track key reliability indicators as a means of benchmarking reliability performance and measuring reliability improvements. This program will include assessing available metrics, developing guidelines for acceptable metrics, maintaining a performance metrics "dashboard" on the NERC website, and developing appropriate reliability performance benchmarks.

810. Information Exchange and Issuance of NERC Advisories, Recommendations and Essential Actions

1. Members of NERC and Bulk Power System owners, operators, and users shall provide NERC with detailed and timely operating experience information and data.

2. In the normal course of operations, NERC disseminates the results of its events analysis findings, lessons learned and other analysis and information gathering to the industry. These findings, lessons learned and other information will be used to guide the Reliability Assessment Program.

3. When NERC determines it is necessary to place the industry or segments of the industry on formal notice of its findings, analyses, and recommendations, NERC will provide such notification in the form of specific operations or equipment Advisories, Recommendations or Essential Actions:

   3.1 Level 1 (Advisories) – purely informational, intended to advise certain segments of the owners, operators and users of the Bulk Power System of findings and lessons learned;

   3.2 Level 2 (Recommendations) – specific actions that NERC is recommending be considered on a particular topic by certain segments of

owners, operators, and users of the Bulk Power System according to each entity's facts and circumstances;

3.3 Level 3 (Essential Actions) – specific actions that NERC has determined are essential for certain segments of owners, operators, or users of the Bulk Power System to take to ensure the reliability of the Bulk Power System. Such Essential Actions require NERC Board approval before issuance.

4. The Bulk Power System owners, operators, and users to which Level 2 (Recommendations) and Level 3 (Essential Actions) notifications apply are to evaluate and take appropriate action on such issuances by NERC. Such Bulk Power System owners, operators, and users shall also provide reports of actions taken and timely updates on progress towards resolving the issues raised in the Recommendations and Essential Actions in accordance with the reporting date(s) specified by NERC.

5. NERC will advise the Commission and other Applicable Governmental Authorities of its intent to issue all Level 1 (Advisories), Level 2 (Recommendations), and Level 3 (Essential Actions) at least five (5) business days prior to issuance, unless extraordinary circumstances exist that warrant issuance less than five (5) business days after such advice. NERC will file a report with the Commission and other Applicable Governmental Authorities no later than thirty (30) days following the date by which NERC has requested the Bulk Power System owners, operators, and users to which a Level 2 (Recommendation) or Level 3 (Essential Action) issuance applies to provide reports of actions taken in response to the notification. NERC's report to the Commission and other Applicable Governmental Authorities will describe the actions taken by the relevant owners, operators, and users of the Bulk Power System and the success of such actions taken in correcting any vulnerability or deficiency that was the subject of the notification, with appropriate protection for Confidential Information or Critical Energy Infrastructure Information.

811. Equipment Performance Data

Through its Generating Availability Data System (GADS), NERC shall collect operating information about the performance of electric generating equipment; provide assistance to those researching information on power plant outages stored in its database; and support equipment reliability as well as availability analyses and other decision-making processes developed by GADS subscribers. GADS data is also used in conducting assessments of generation resource adequacy.

SECTION 900 — TRAINING AND EDUCATION

901. Scope of the Training and Education Program

Assuring the Reliable Operation of the North American Bulk Power System requires informed knowledgeable and skilled personnel. NERC shall develop a program to oversee the coordination and delivery of learning materials, resources, and activities to allow for training and education of:

1. ERO Enterprise staff supporting statutory and delegation-related activities; and

2. Bulk Power System industry participants consistent with ERO functional program requirements.

902. Continuing Education Program

1. NERC shall develop and and maintain a continuing education program to approve those activities and entities meeting NERC continuing education requirements.

2. The Personnel Subcommittee (PS), which reports to the NERC Operating Committee, is the governing body of the NERC Continuing Education Program that oversees development and implementation of the Continuing Education Program requirements.

3. The PS shall develop and update, as necessary, a manual, approved by the Operating Committee, which describes the following:

   3.1 Requirements for approving contining education Providers and activities;

   3.2 Requirements for auditing continuing education Providers and activities;

   3.3 Multi-layer review process for disputed application reviews, interpretations of guideline and standards, probation or suspension of NERC-approved Provider status, and Continuing Education Hour disputes; and

   3.4 Requirements on fees for continuing education Providers and activities.

SECTION 1000 — SITUATION AWARENESS AND INFRASTRUCTURE SECURITY

1001. Situation Awareness

NERC shall through the use of Reliability Coordinators and available tools, monitor present conditions on the Bulk Power System and provide leadership coordination, technical expertise, and assistance to the industry in responding to events as necessary. To accomplish these goals, NERC will:

1. Maintain real-time situation awareness of conditions on the Bulk Power System;

2. Notify the industry of significant Bulk Power System events that have occurred in one area, and which have the potential to impact reliability in other areas;

3. Maintain and strengthen high-level communication, coordination, and cooperation with governments and government agencies regarding real-time conditions; and

4. Enable the Reliable Operation of interconnected Bulk Power Systems by facilitating information exchange and coordination among reliability service organizations.

1002. Reliability Support Services

NERC may assist in the development of tools and other support services for the benefit of Reliability Coordinators and other system operators to enhance reliability, operations and planning. NERC will work with the industry to identify new tools, collaboratively develop requirements, support development, provide an incubation period, and at the end of that period, transition the tool or service to another group or owner for long term operation of the tool or provision of the service. To accomplish this goal, NERC will:

1. Collaborate with industry to determine the necessity of new tools or services to enhance reliability;

2. For those tools that the collaborative process determines should proceed to a development phase, provide a start-up mechanism and development system;

3. Implement the tool either on its own or through an appropriate group or organization; and

4. Where NERC conducts the implementation phase of a new tool or service, develop a transition plan to turn maintenance and provision of the tool or service over to an organization identified in the development stage.

In addition to tools developed as a result of a collaborative process with industry, NERC may develop reliability tools on its own, but will consult with industry concerning the need for the tool prior to proceeding to development.

Tools and services being maintained by NERC as of January 1, 2012, will be reviewed and, as warranted, transitioned to an appropriate industry group or organization. NERC will develop and maintain a strategic reliability tools plan that will list the tools and services being maintained by NERC, and, where applicable, the plans for transition to an appropriate industry group or organization.

1003. Infrastructure Security Program

NERC shall coordinate electric industry activities to promote Critical Infrastructure protection of the Bulk Power System in North America by taking a leadership role in Critical Infrastructure protection of the electricity sector so as to reduce vulnerability and improve mitigation and protection of the electricity sector's Critical Infrastructure. To accomplish these goals, NERC shall perform the following functions.

1. Electric Sector Information Sharing and Analysis Center (ESISAC)

    1.1 NERC shall serve as the electricity sector's sector coordinator and operate its Information Sharing and Analysis Center to gather information and communicate security-related threats and incidents within the sector, with United States and Canadian government agencies, and with other Critical Infrastructure sectors.

    1.2 NERC shall improve the capability of the ESISAC to analyze security threats and incident information and provide situational assessments for the electricity sector and governments.

    1.3 NERC shall work closely with the United States Department of Homeland Security, Department of Energy, Natural Resources Canada, and Public Safety and Emergency Preparedness Canada.

    1.4 NERC shall strengthen and expand these functions and working relationships with the electricity sector, other Critical Infrastructure industries, governments, and government agencies throughout North America to ensure the protection of the infrastructure of the Bulk Power System.

    1.5 NERC shall fill the role of the Electricity Sector Coordinating Council and coordinate with the Government Coordinating Council.

    1.6 NERC shall coordinate with other Critical Infrastructure sectors through active participation with the other Sector Coordinating Councils, the other ISACs, and the National Infrastructure Advisory Committee.

    1.7 NERC shall encourage and participate in coordinated Critical Infrastructure protection exercises, including interdependencies with other Critical Infrastructure sectors.

2. Security Planning

2.1 NERC shall take a risk management approach to Critical Infrastructure protection, considering probability and severity, and recognizing that mitigation and recovery can be practical alternatives to prevention.

2.2 NERC shall keep abreast of the changing threat environment through collaboration with government agencies.

2.3 NERC shall develop criteria to identify critical physical and cyber assets, assess security threats, identify risk assessment methodologies, and assess effectiveness of physical and cyber protection measures.

2.4 NERC shall enhance and maintain the Bulk Power System critical spare transformer program, encourage increased participation by asset owners, and continue to assess the need to expand this program to include other critical Bulk Power System equipment.

2.5 NERC shall support implementation of the Critical Infrastructure Protection Standards through education and outreach.

2.6 NERC shall review and improve existing security guidelines, develop new security guidelines to meet the needs of the electricity sector, and consider whether any guidelines should be developed into Reliability Standards.

2.7 NERC shall conduct education and outreach initiatives to increase awareness and respond to the needs of the electricity sector.

2.8 NERC shall strengthen relationships with federal, state, and provincial government agencies on Critical Infrastructure protection matters.

2.9 NERC shall maintain and improve mechanisms for the sharing of sensitive or classified information with federal, state, and provincial government agencies on Critical Infrastructure protection matters; work with DOE and DHS to implement the National Infrastructure Protection Plan, as applicable to the electricity sector; and coordinate this work with PSEPC.

2.10 NERC shall improve methods to better assess the impact of a possible physical attack on the Bulk Power System and means to deter, mitigate, and respond following an attack.

2.11 NERC shall assess the results of vulnerability assessments and enhance the security of system control and data acquisition (SCADA) and process control systems by developing methods to detect an emerging cyber attack and the means to mitigate impacts on the Bulk Power Systems.

2.12 NERC shall work with the National SCADA Test Bed and the Process Control Systems Forum to accelerate the development of technology that will enhance the security, safety, and reliability of process control and SCADA systems.

SECTION 1100 — ANNUAL NERC BUSINESS PLANS AND BUDGETS

1101. Scope of Business Plans and Budgets

The Board shall determine the content of the budgets to be submitted to the Applicable Governmental Authorities with consultation from the members of the Member Representatives Committee, Regional Entities, and others in accordance with the Bylaws. The Board shall identify any activities outside the scope of NERC's statutory reliability functions, if any, and the appropriate funding mechanisms for those activities.

1102. NERC Funding and Cost Allocation

1. In order that NERC's costs shall be fairly allocated among Interconnections and among Regional Entities, the NERC funding mechanism for all statutory functions shall be based on Net Energy for Load (NEL).

2. NERC's costs shall be allocated so that all Load (or, in the case of costs for an Interconnection or Regional Entity, all Load within that Interconnection or Regional Entity) bears an equitable share of such costs based on NEL.

3. Costs shall be equitably allocated between countries or Regional Entities thereof for which NERC has been designated or recognized as the Electric Reliability Organization.

4. Costs incurred to accomplish the statutory functions for one Interconnection, Regional Entity, or group of entities will be directly assigned to that Interconnection, Regional Entity, or group of entities provided that such costs are allocated equitably to end-users based on Net Energy for Load.

1103. NERC Budget Development

1. The NERC annual budget process shall be scheduled and conducted for each calendar year so as to allow a sufficient amount of time for NERC to receive Member inputs, develop the budget, and receive Board and, where authorized by applicable legislation or agreement, Applicable Governmental Authority approval of the NERC budget for the following fiscal year, including timely submission of the proposed budget to FERC for approval in accordance with FERC regulations.

2. The NERC budget submittal to Applicable Governmental Authorities shall include provisions for all ERO functions, all Regional Entity delegated functions as specified in delegation agreements and reasonable reserves and contingencies.

3. The NERC annual budget submittal to Applicable Governmental Authorities shall include description and explanation of NERC's proposed ERO program activities for the year; budget component justification based on statutory or other authorities; explanation of how each budgeted activity lends itself to the accomplishment of the statutory or other authorities; sufficiency of resources provided for in the budget to carry out the ERO program responsibilities; explanation of the calculations and

budget estimates; identification and explanation of changes in budget components from the previous year's budget; information on staffing and organization charts; and such other information as is required by FERC and other Applicable Governmental Authorities having authority to approve the proposed budget.

4. NERC shall develop, in consultation with the Regional Entities, a reasonable and consistent system of accounts, to allow a meaningful comparison of actual results at the NERC and Regional Entity level by the Applicable Governmental Authorities.

1104. Submittal of Regional Entity Budgets to NERC

1. Each Regional Entity shall submit its proposed annual budget for carrying out its delegated authority functions as well as all other activities and funding to NERC in accordance with a schedule developed by NERC and the Regional Entities, which shall provide for the Regional Entity to submit its final budget that has been approved by its board of directors or other governing body no later than July 1 of the prior year, in order to provide sufficient time for NERC's review and comment on the proposed budget and approval of the Regional Entity budget by the NERC Board of Trustees in time for the NERC and Regional Entity budgets to be submitted to FERC and other Applicable Governmental Authorities for approval in accordance with their regulations. The Regional Entity's budget shall include supporting materials in accordance with the budget and reporting format developed by NERC and the Regional Entities, including the Regional Entity's complete business plan and organization chart, explaining the proposed collection of all dues, fees, and charges and the proposed expenditure of funds collected in sufficient detail to justify the requested funding collection and budget expenditures.

2. NERC shall review and approve each Regional Entity's budget for meeting the requirements of its delegated authority. Concurrent with approving the NERC budget, NERC shall review and approve, or reject, each Regional Entity budget for filing.

3. NERC shall also have the right to review from time to time, in reasonable intervals but no less frequently than every three years, the financial books and records of each Regional Entity having delegated authority in order to ensure that the documentation fairly represents in all material aspects appropriate funding of delegated functions.

1105. Submittal of NERC and Regional Entity Budgets to Governmental Authorities for Approval

1. NERC shall file for approval by the Applicable Governmental Authorities at least 130 days in advance of the start of each fiscal year. The filing shall include: (1) the complete NERC and Regional Entity budgets including the business plans and organizational charts approved by the Board, (2) NERC's annual funding requirement (including Regional Entity costs for delegated functions), and (3) the mechanism for assessing charges to recover that annual funding requirement,

together with supporting materials in sufficient detail to support the requested funding requirement.

2. NERC shall seek approval from each Applicable Governmental Authority requiring such approval for the funding requirements necessary to perform ERO activities within their jurisdictions.

1106. NERC and Regional Entity Billing and Collections

1. NERC shall request the Regional Entities to identify all Load-Serving Entities[3] within each Regional Entity and the NEL assigned to each Load-Serving Entity, and the Regional Entities shall supply the requested information. The assignment of a funding requirement to an entity shall not be the basis for determining that the entity must be registered in the Compliance Registry.

2. NERC shall accumulate the NEL by Load-Serving Entities for each Applicable Governmental Authority and submit the proportional share of NERC funding requirements to each Applicable Governmental Authority for approval together with supporting materials in sufficient detail to support the requested funding requirement.

3. NEL reported by Balancing Authorities within a Region shall be used to rationalize and validate amounts allocated for collection through Regional Entity processes.

4. The billing and collection processes shall provide:

   4.1 A clear validation of billing and application of payments.

   4.2 A minimum of data requests to those being billed.

   4.3 Adequate controls to ensure integrity in the billing determinants including identification of entities responsible for funding NERC's activities.

   4.4 Consistent billing and collection terms.

5. NERC will bill and collect all budget requirements approved by Applicable Governmental Authorities (including the funds required to support those functions assigned to the Regional Entities through the delegation agreements) directly from the Load-Serving Entities or their designees or as directed by particular Applicable Governmental Authorities, except where the Regional Entity is required to collect the budget requirements for NERC, in which case the Regional Entity will collect directly from the Load-Serving Entities or as otherwise provided by agreement and submit funds to NERC. Alternatively, a load-serving

[3] A Regional Entity may allocate funding obligations using an alternative method approved by NERC and by FERC and other Applicable Governmental Authorities, as provided for in the regional delegation agreement.

entity may pay its allocated ERO costs through a Regional Entity managed collection mechanism.

6. NERC shall set a minimum threshold limit on the billing of small LSEs to minimize the administrative burden of collection.

7. NERC shall pursue any non-payments and shall request assistance from Applicable Governmental Authorities as necessary to secure collection.

8. In the case where a Regional Entity performs the collection for ERO, the Regional Entity will not be responsible for non-payment in the event that a user, owner or operator of the Bulk Power System does not pay its share of dues, fees and charges in a timely manner, provided that such a Regional Entity shall use reasonably diligent efforts to collect dues, fees, and other charges from all entities obligated to pay them. However, any revenues not paid shall be recovered from others within the same Region to avoid cross-subsidization between Regions.

9. Both NERC and the Regional Entities also may bill members or others for functions and services not within statutory requirements or otherwise authorized by the Applicable Governmental Authorities. Costs and revenues associated with these functions and services shall be separately identified and not commingled with billings associated with the funding of NERC or of the Regional Entities for delegated activities.

1107. Penalty Applications

1. Where NERC or a Regional Entity initiates a compliance monitoring and enforcement process that leads to imposition of a Penalty, the entity that initiated the process shall receive any Penalty monies imposed and collected as a result of that process, unless a different disposition of the Penalty monies is provided for in the delegation agreement, or in a contract or a disposition of the violation that is approved by NERC and FERC.

2. All funds from financial Penalties assessed in the United States received by the entity initiating the compliance monitoring and enforcement process shall be applied as a general offset to the entity's budget requirements for the subsequent fiscal year, if received by July 1, or for the second subsequent fiscal year, if received on or after July 1. Funds from financial Penalties shall not be directly applied to any program maintained by the entity conducting the compliance monitoring and enforcement process. Funds from financial Penalties assessed against a Canadian entity shall be applied as specified by legislation or agreement.

3. In the event that a compliance monitoring and enforcement process is conducted jointly by NERC and a Regional Entity, the Regional Entity shall receive the Penalty monies and offset the Regional Entity's budget requirements for the subsequent fiscal year.

4. Exceptions or alternatives to the foregoing provisions will be allowed if approved by NERC and by FERC or any other Applicable Governmental Authority.

1108. Special Assessments

On a demonstration of unforeseen and extraordinary circumstances requiring additional funds prior to the next funding cycle, NERC shall file with the Applicable Governmental Authorities, where authorized by applicable legislation or agreement, for authorization for an amended or supplemental budget for NERC or a Regional Entity and, if necessary under the amended or supplemental budget, to collect a special or additional assessment for statutory functions of NERC or the Regional Entity. Such filing shall include supporting materials to justify the requested funding, including any departure from the approved funding formula or method.

SECTION 1200 — REGIONAL DELEGATION AGREEMENTS

1201. Pro Forma Regional Delegation Agreement

NERC shall develop and maintain a pro forma Regional Entity delegation agreement, which shall serve as the basis for negotiation of consistent agreements for the delegation of ERO functions to Regional Entities.

1202. Regional Entity Essential Requirements

NERC shall establish the essential requirements for an entity to become qualified and maintain good standing as a Regional Entity.

1203. Negotiation of Regional Delegation Agreements

NERC shall, for all areas of North America that have provided NERC with the appropriate authority, negotiate regional delegation agreements for the purpose of ensuring all areas of the North American Bulk Power Systems are within a Regional Entity Region. In the event NERC is unable to reach agreement with Regional Entities for all areas, NERC shall provide alternative means and resources for implementing NERC functions within those areas. No delegation agreement shall take effect until it has been approved by the Applicable Governmental Authority.

1204. Conformance to Rules and Terms of Regional Delegation Agreements

NERC and each Regional Entity shall comply with all applicable ERO Rules of Procedure and the obligations stated in the regional delegation agreement.

1205. Sub-delegation

The Regional Entity shall not sub-delegate any responsibilities and authorities delegated to it by its regional delegation agreement with NERC except with the approval of NERC and FERC and other Applicable Governmental Authorities. Responsibilities and authorities may only be sub-delegated to another Regional Entity. Regional Entities may share resources with one another so long as such arrangements do not result in cross-subsidization or in any sub-delegation of authorities.

1206. Nonconformance to Rules or Terms of Regional Delegation Agreement

If a Regional Entity is unable to comply or is not in compliance with an ERO Rule of Procedure or the terms of the regional delegation agreement, the Regional Entity shall immediately notify NERC in writing, describing the area of nonconformance and the reason for not being able to conform to the Rule of Procedure. NERC shall evaluate each case and inform the affected Regional Entity of the results of the evaluation. If NERC determines that a Rule of Procedure or term of the regional delegation agreement has been violated by a Regional Entity or cannot practically be implemented by a Regional Entity, NERC shall notify the Applicable Governmental Authorities and take any actions necessary to address the situation.

1207. Regional Entity Audits

Approximately every five years and more frequently if necessary for cause, NERC shall audit each Regional Entity to verify that the Regional Entity continues to comply with NERC Rules of Procedure and the obligations of NERC delegation agreement. Audits of Regional Entities shall be conducted, to the extent practical, based on professional auditing standards recognized in the U.S., including Generally Accepted Auditing Standards, Generally Accepted Government Auditing Standards, and standards sanctioned by the Institute of Internal Auditors, and if applicable to the coverage of the audit, may be based on Canadian or other international standards. The audits required by this Section 1207 shall not duplicate the audits of Regional Entity Compliance Monitoring and Enforcement Programs provided for in **Appendix 4A**, Audit of Regional Compliance Programs, to these Rules of Procedure.

1208. Process for Considering Registered Entity Requests to Transfer to Another Regional Entity

1. A Registered Entity that is registered in the Region of one Regional Entity and believes its registration should be transferred to a different Regional Entity may submit a written request to both Regional Entities requesting that they process the proposed transfer in accordance with this section. The Registered Entity's written request shall set forth the reasons the Registered Entity believes justify the proposed transfer and shall describe any impacts of the proposed transfer on other Bulk Power System owners, operators, and users.

2. After receiving the Registered Entity's written request, the two Regional Entities shall consult with each other as to whether they agree or disagree that the requested transfer is appropriate. The Regional Entities may also consult with affected Reliability Coordinators, Balancing Authorities and Transmission Operators as appropriate. Each Regional Entity shall post the request on its website for public comment period of 21 days. In evaluating the proposed transfer, the Regional Entities shall consider the location of the Registered Entity's Bulk Power System facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators; and users, the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments to other Load-Serving Entities of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity would be transitioned from the current Regional Entity to the transferee Regional Entity; along with any other reasons for the proposed transfer stated by the Registered Entity and any other reasons either Regional Entity considers relevant. The Regional Entities may request that the Registered Entity provide additional data and information concerning the proposed transfer for the Regional Entities' use in their evaluation. The Registered Entity's current Regional Entity shall notify the Registered Entity

in writing as to whether (i) the two Regional Entities agree that the requested transfer is appropriate, (ii) the two Regional Entities agree that the requested transfer is not appropriate and should not be processed further, or (iii) the two Regional Entities disagree as to whether the proposed transfer is appropriate.

3. If the two Regional Entities agree that the requested transfer is appropriate, they shall submit a joint written request to NERC requesting that the proposed transfer be approved and that the delegation agreement between NERC and each of the Regional Entities be amended accordingly. The Regional Entities' joint written submission to NERC shall describe the reasons for the proposed transfer; the location of the Registered Entity's Bulk Power System Facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators, and users; the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity will be transitioned from the current Regional Entity to the transferee Regional Entity. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

4. If the two Regional Entities do not agree with each other that the proposed transfer is appropriate, the Regional Entity supporting the proposed transfer shall, if requested by the Registered Entity, submit a written request to NERC to approve the transfer and the related delegation agreement amendments. The Regional Entity's written request shall include the information specified in Section 1208.3. The Regional Entity that does not believe the proposed transfer is appropriate will be allowed to submit a written statement to NERC explaining why the Regional Entity believes the transfer is not appropriate and should not be approved. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

5. Prior to action by the NERC Board of Trustees on a proposed transfer of registration under Section 1208.3 or 1208.4, NERC shall post information concerning the proposed transfer, including the submissions from the Regional Entities, on its website for at least twenty-one (21) days for the purpose of receiving public comment.

6. If the NERC Board of Trustees disapproves a proposed transfer presented to it pursuant to either Section 1208.3 or 1208.4, the Regional Entity or Regional Entities that believe the transfer is appropriate may, if requested to do so by the Registered Entity, file a petition with FERC pursuant to 18 C.F.R. section 39.8(f) and (g) requesting that FERC order amendments to the delegation agreements of the two Regional Entities to effectuate the proposed transfer.

7. No transfer of a Registered Entity from one Regional Entity to another Regional Entity shall be effective (i) unless approved by FERC, and (ii) any earlier than the first day of January of the second calendar year following approval by FERC, unless an earlier effective date is agreed to by both Regional Entities and NERC and approved by FERC.

SECTION 1300 — COMMITTEES

1301. Establishing Standing Committees

The Board may from time to time create standing committees. In doing so, the Board shall approve the charter of each committee and assign specific authority to each committee necessary to conduct business within that charter. Each standing committee shall work within its Board-approved charter and shall be accountable to the Board for performance of its Board-assigned responsibilities. A NERC standing committee may not delegate its assigned work to a member forum, but, in its deliberations, may request the opinions of and consider the recommendations of a member forum.

1302. Committee Membership

Each committee shall have a defined membership composition that is explained in its charter. Committee membership may be unique to each committee, and can provide for balanced decision-making by providing for representatives from each Sector or, where Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area, by bringing together a wide diversity of opinions from industry experts with outstanding technical knowledge and experience in a particular subject area. Committee membership shall also provide the opportunity for an equitable number of members from the United States and Canada, based approximately on proportionate Net Energy for Load. All committees and other subgroups (except for those organized on other than a Sector basis because Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area) must ensure that no two stakeholder Sectors are able to control the vote on any matter, and no single Sector is able to defeat a matter. With regard to committees and subgroups pertaining to development of, interpretation of, or compliance with Reliability Standards, NERC shall provide a reasonable opportunity for membership from Sectors desiring to participate. Committees and subgroups organized on other than a Sector basis shall be reported to the NERC Board and the Member Representatives Committee, along with the reasons for constituting the committee or subgroup in the manner chosen. In such cases and subject to reasonable restrictions necessary to accomplish the mission of such committee or subgroup, NERC shall provide a reasonable opportunity for additional participation, as members or official observers, for Sectors not represented on the committee or subgroup.

1303. Procedures for Appointing Committee Members

Committee members shall be nominated and selected in a manner that is open, inclusive, and fair. Unless otherwise stated in these Rules of Procedure or approved by the Board, all committee member appointments shall be approved by the board, and committee officers shall be appointed by the Chairman of the Board.

1304. Procedures for Conduct of Committee Business

1. Notice to the public of the dates, places, and times of meetings of all committees, and all nonconfidential material provided to committee members, shall be posted on NERC's website at approximately the same time that notice is given to

committee members. Meetings of all standing committees shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance enforcement matters, litigation, or commercially sensitive or Critical Energy Infrastructure Information of any entity.

2. NERC shall maintain a set of procedures, approved by the Board, to guide the conduct of business by standing committees.

1305. Committee Subgroups

Standing committees may appoint subgroups using the same principles as in Section 1302.

SECTION 1400 — AMENDMENTS TO THE NERC RULES OF PROCEDURE

1401. Proposals for Amendment or Repeal of Rules of Procedure

In accordance with the Bylaws of NERC, requests to amend or repeal the Rules of Procedure may be submitted by (1) any fifty Members of NERC, which number shall include Members from at least three membership Sectors, (2) the Member Representatives Committee, (3) a committee of NERC to whose function and purpose the Rule of Procedure pertains, or (4) an officer of NERC.

1402. Approval of Amendment or Repeal of Rules of Procedure

Amendment to or repeal of Rules of Procedure shall be approved by the Board after public notice and opportunity for comment in accordance with the Bylaws of NERC. In approving changes to the Rules of Procedure, the Board shall consider the inputs of the Member Representatives Committee, other ERO committees affected by the particular changes to the Rules of Procedure, and other stakeholders as appropriate. After Board approval, the amendment or repeal shall be submitted to the Applicable Governmental Authorities for approval, where authorized by legislation or agreement. No amendment to or repeal of the Rules of Procedure shall be effective until it has been approved by the Applicable Governmental Authorities.

SECTION 1500 — CONFIDENTIAL INFORMATION

1501. Definitions

1. **Confidential Information** means (i) Confidential Business and Market Information; (ii) Critical Energy Infrastructure Information; (iii) personnel information that identifies or could be used to identify a specific individual, or reveals personnel, financial, medical, or other personal information; (iv) work papers, including any records produced for or created in the course of an evaluation or audit; (v) investigative files, including any records produced for or created in the course of an investigation; or (vi) Cyber Security Incident Information; provided, that public information developed or acquired by an entity shall be excluded from this definition.

2. **Confidential Business and Market Information** means any information that pertains to the interests of any entity, that was developed or acquired by that entity, and that is proprietary or competitively sensitive.

3. **Critical Energy Infrastructure Information** means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.

4. **Critical Infrastructure** means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

5. **Cyber Security Incident Information** means any information related to, describing, or which could be used to plan or cause a Cyber Security Incident.

1502. Protection of Confidential Information

1. **Identification of Confidential Information** — An owner, operator, or user of the Bulk Power System and any other party (the "Submitting Entity") shall mark as confidential any information that it submits to NERC or a Regional Entity (the "Receiving Entity") that it reasonably believes contains Confidential Information as defined by these Rules of Procedure, indicating the category or categories defined in Section 1501 in which the information falls. If the information is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the Submitting Entity shall so indicate and provide supporting references and details.

2. **Confidentiality** — Except as provided herein, a Receiving Entity shall keep in confidence and not copy, disclose, or distribute any Confidential Information or

any part thereof without the permission of the Submitting Entity, except as otherwise legally required.

3. **Information no longer Confidential –** If a Submitting Entity concludes that information for which it had sought confidential treatment no longer qualifies for that treatment, the Submitting Entity shall promptly so notify NERC or the relevant Regional Entity.

1503. Requests for Information

1. **Limitation** — A Receiving Entity shall make information available only to one with a demonstrated need for access to the information from the Receiving Entity.

2. **Form of Request** — A person with such a need may request access to information by using the following procedure:

   2.1 The request must be in writing and clearly marked "Request for Information."

   2.2 The request must identify the individual or entity that will use the information, explain the requester's need for access to the information, explain how the requester will use the information in furtherance of that need, and state whether the information is publicly available or available from another source or through another means. If the requester seeks access to information that is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the requester shall describe how it qualifies to receive such information.

   2.3 The request must stipulate that, if the requester does not seek public disclosure, the requester will maintain as confidential any information received for which a Submitting Party has made a claim of confidentiality in accordance with NERC's rules. As a condition to gaining access to such information, a requester shall execute a non-disclosure agreement in a form approved by NERC's Board of Trustees.

3. **Notice and Opportunity for Comment** — Prior to any decision to disclose information marked as confidential, the Receiving Entity shall provide written notice to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed. Failure to provide such comments or otherwise respond is not deemed waiver of the claim of confidentiality.

4. **Determination by ERO or Regional Entity** — Based on the information provided by the requester under Rule 1503.2, any comments provided by the Submitting Entity, and any other relevant available information, the chief

executive officer or his or her designee of the Receiving Entity shall determine whether to disclose such information.

5. **Appeal** — A person whose request for information is denied in whole or part may appeal that determination to the President of NERC (or the President's designee) within 30 days of the determination. Appeals filed pursuant to this Section must be in writing, addressed to the President of NERC (or the President's designee), and clearly marked "Appeal of Information Request Denial."

   NERC will provide written notice of such appeal to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed; provided that any such comments must be received within 30 days of the notice and any failure to provide such comments or otherwise respond is not deemed a waiver of the claim of confidentiality.

   The President of NERC (or the President's designee) will make a determination with respect to any appeal within 30 days. In unusual circumstances, this time limit may be extended by the President of NERC (or the President's designee), who will send written notice to the requester setting forth the reasons for the extension and the date on which a determination on the appeal is expected.

6. **Disclosure of Information** — In the event the Receiving Entity, after following the procedures herein, determines to disclose information designated as Confidential Information, it shall provide the Submitting Entity no fewer than 21 days' written notice prior to releasing the Confidential Information in order to enable such Submitting Entity to (a) seek an appropriate protective order or other remedy, (b) consult with the Receiving Entity with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Section. Should a Receiving Entity be required to disclose Confidential Information, or should the Submitting Entity waive objection to disclosure, the Receiving Entity shall furnish only that portion of the Confidential Information which the Receiving Entity's counsel advises is legally required.

7. **Posting of Determinations on Requests for Disclosure of Confidential Information** — Upon making its determination on a request for disclosure of Confidential Information, NERC or the Regional Entity, as applicable, shall (i) notify the requester that the request for disclosure is granted or denied, (ii) publicly post any determination to deny the request to disclose Confidential Information, including in such posting an explanation of the reasons for the denial (but without in such explanation disclosing the Confidential Information), and (iii) publicly post any determination that information claimed by the Submitting Entity to be Confidential Information is not Confidential Information (but without in such posting disclosing any information that has been determined to be Confidential Information).

1504. Employees, Contractors and Agents

A Receiving Entity shall ensure that its officers, trustees, directors, employees, subcontractors and subcontractors' employees, and agents to whom Confidential Information is exposed are under obligations of confidentiality that are at least as restrictive as those contained herein.

1505. Provision of Information to FERC and Other Governmental Authorities

1. **Request** — A request from FERC for reliability information with respect to owners, operators, and users of the Bulk Power System within the United States is authorized by Section 215 of the Federal Power Act. Other Applicable Governmental Authorities may have similar authorizing legislation that grants a right of access to such information. Unless otherwise directed by FERC or its staff or the other Applicable Governmental Authority requesting the information, upon receiving such a request, a Receiving Entity shall provide contemporaneous notice to the applicable Submitting Entity. In its response to such a request, a Receiving Entity shall preserve any mark of confidentiality and shall notify FERC or other Applicable Governmental Authorities that the Submitting Entity has marked the information as confidential.

2. **Continued Confidentiality** — Each Receiving Entity shall continue to treat as confidential all Confidential Information that it has submitted to NERC or to FERC or another Applicable Governmental Authority, until such time as FERC or the other Applicable Governmental Authority authorizes disclosure of such information.

1506. Permitted Disclosures

1. **Confirmed Violations** — Nothing in this Section 1500 shall prohibit the disclosure of a violation at the point when the matter is filed with an Applicable Governmental Authority as a Notice of Penalty, the "violator" admits to the violation, or the alleged violator and NERC or the Regional Entity reach a settlement regarding the violation.

2. **Compliance Information** — NERC and the Regional Entities are authorized to exchange Confidential Information related to evaluations, Compliance Audits, and Compliance Investigations in furtherance of the Compliance Monitoring and Enforcement Program, on condition they continue to maintain the confidentiality of such information.

1507. Remedies for Improper Disclosure

Any person engaged in NERC or Regional Entity activity under Section 215 of the Federal Power Act or the equivalent laws of other Applicable Governmental Authorities who improperly discloses information determined to be confidential may lose access to Confidential Information on a temporary or permanent basis and may be subject to adverse personnel action, including suspension or termination. Nothing in Section 1500

precludes an entity whose information was improperly disclosed from seeking a remedy in an appropriate court.

SECTION 1600 — REQUESTS FOR DATA OR INFORMATION

1601. Scope of a NERC or Regional Entity Request for Data or Information

Within the United States, NERC and Regional Entities may request data or information that is necessary to meet their obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Commission's regulations, 18 C.F.R. § 39.2(d). In other jurisdictions NERC and Regional Entities may request comparable data or information, using such authority as may exist pursuant to these Rules of Procedure and as may be granted by Applicable Governmental Authorities in those other jurisdictions. The provisions of Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information; the Requirements in the Reliability Standards govern. The provisions of Section 1600 shall also not apply to data or information requested in connection with a compliance or enforcement action under Section 215 of the Federal Power Act, Section 400 of these Rules of Procedure, or any procedures adopted pursuant to those authorities, in which case the Rules of Procedure applicable to the production of data or information for compliance and enforcement actions shall apply.

1602. Procedure for Authorizing a NERC Request for Data or Information

1. NERC shall provide a proposed request for data or information or a proposed modification to a previously-authorized request, including the information specified in Section 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability at least twenty-one (21) days prior to initially posting the request or modification for public comment. Submission of the proposed request or modification to the Office of Electric Reliability is for the information of the Commission. NERC is not required to receive any approval from the Commission prior to posting the proposed request or modification for public comment in accordance with Section 1602.2 or issuing the request or modification to Reporting Entities following approval by the Board of Trustees.

2. NERC shall post a proposed request for data or information or a proposed modification to a previously authorized request for data or information for a forty-five (45) day public comment period.

    2.1. A proposed request for data or information shall contain, at a minimum, the following information: (i) a description of the data or information to be requested, how the data or information will be used, and how the availability of the data or information is necessary for NERC to meet its obligations under applicable laws and agreements; (ii) a description of how the data or information will be collected and validated; (iii) a description of the entities (by functional class and jurisdiction) that will be required to provide the data or information ("Reporting Entities"); (iv) the schedule or due date for the data or information; (v) a description of any restrictions on disseminating the data or information (e.g., "Confidential Information," "Critical Energy Infrastructure Information," "aggregating"

or "identity masking"); and (vi) an estimate of the relative burden imposed on the Reporting Entities to accommodate the data or information request.

2.2. A proposed modification to a previously authorized request for data or information shall explain (i) the nature of the modifications; (ii) an estimate of the burden imposed on the Reporting Entities to accommodate the modified data or information request, and (iii) any other items from Section 1602.2.1 that require updating as a result of the modifications.

3. After the close of the comment period, NERC shall make such revisions to the proposed request for data or information as are appropriate in light of the comments. NERC shall submit the proposed request for data or information, as revised, along with the comments received, NERC's evaluation of the comments and recommendations, to the Board of Trustees.

4. In acting on the proposed request for data or information, the Board of Trustees may authorize NERC to issue it, modify it, or remand it for further consideration.

5. NERC may make minor changes to an authorized request for data or information without Board approval. However, if a Reporting Entity objects to NERC in writing to such changes within 21 days of issuance of the modified request, such changes shall require Board approval before they are implemented.

6. Authorization of a request for data or information shall be final unless, within thirty (30) days of the decision by the Board of Trustees, an affected party appeals the authorization under this Section 1600 to the Applicable Governmental Authority.

1603. Owners, Operators, and Users to Comply

Owners, operators, and users of the Bulk Power System registered on the NERC Compliance Registry shall comply with authorized requests for data and information. In the event a Reporting Entity within the United States fails to comply with an authorized request for data or information under Section 1600, NERC may request the Commission to exercise its enforcement authority to require the Reporting Entity to comply with the request for data or information and for other appropriate enforcement action by the Commission. NERC will make any request for the Commission to enforce a request for data or information through a non-public submission to the Commission's enforcement staff.

1604. Requests by Regional Entity for Data or Information

1. A Regional Entity may request that NERC seek authorization for a request for data or information to be applicable within the Region of the Regional Entity, either as a freestanding request or as part of a proposed NERC request for data or information. Any such request must be consistent with this Section 1600.

2. A Regional Entity may also develop its own procedures for requesting data or information, but any such procedures must include at least the same procedural

elements as are included in this Section 1600. Any such Regional Entity procedures or changes to such procedures shall be submitted to NERC for approval. Upon approving such procedures or changes thereto, NERC shall file the proposed procedures or proposed changes for approval by the Commission and any other Applicable Governmental Authorities applicable to the Regional Entity. The Regional Entity procedures or changes to such procedures shall not be effective in a jurisdiction until approved by, and in accordance with any revisions directed by, the Commission or other Applicable Governmental Authority.

1605. Confidentiality

If the approved data or information request includes a statement under Section 1602.1.1(v) that the requested data or information will be held confidential or treated as Critical Energy Infrastructure Information, then the applicable provisions of Section 1500 will apply without further action by a Submitting Entity. A Submitting Entity may designate any other data or information as Confidential Information pursuant to the provisions of Section 1500, and NERC or the Regional Entity shall treat that data or information in accordance with Section 1500. NERC or a Regional Entity may utilize additional protective procedures for handling particular requests for data or information as may be necessary under the circumstances.

1606. Expedited Procedures for Requesting Time-Sensitive Data or Information

1. In the event NERC or a Regional Entity must obtain data or information by a date or within a time period that does not permit adherence to the time periods specified in Section 1602, the procedures specified in Section 1606 may be used to obtain the data or information. Without limiting the circumstances in which the procedures in Section 1606 may be used, such circumstances include situations in which it is necessary to obtain the data or information (in order to evaluate a threat to the reliability or security of the Bulk Power System, or to comply with a directive in an order issued by the Commission or by another Applicable Governmental Authority) within a shorter time period than possible under Section 1602. The procedures specified in Section 1606 may only be used if authorized by the NERC Board of Trustees prior to activation of such procedures.

2. Prior to posting a proposed request for data or information, or a modification to a previously-authorized request, for public comment under Section 1606, NERC shall provide the proposed request or modification, including the information specified in paragraph 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability. The submission to the Commission's Office of Electric Reliability shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information. The submission shall be made to the Commission's Office of Electric Reliability as far in advance, up to twenty-one (21) days, of the posting of the proposed request or modification for public comments as is reasonably possible under the circumstances, but in no event less than two (2) days in advance of the public posting of the proposed request or modification.

3. NERC shall post the proposed request for data or information or proposed modification to a previously-authorized request for data or information for a public comment period that is reasonable in duration given the circumstances, but in no event shorter than five (5) days. The proposed request for data or information or proposed modification to a previously-authorized request for data or information shall include the information specified in Section 1602.2.1 or 1602.2.2, as applicable, and shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information.

4. The provisions of Sections 1602.3, 1602.4, 1602.5 and 1602.6 shall be applicable to a request for data or information or modification to a previously-authorized request for data or information developed and issued pursuant to Section 1606, except that (a) if NERC makes minor changes to an authorized request for data or information without Board approval, such changes shall require Board approval if a Reporting Entity objects to NERC in writing to such changes within five (5) days of issuance of the modified request; and (b) authorization of the request for data or information shall be final unless an affected party appeals the authorization of the request by the Board of Trustees to the Applicable Governmental Authority within five (5) days following the decision of the Board of Trustees authorizing the request, which decision shall be promptly posted on NERC's website.

SECTION 1700 — CHALLENGES TO DETERMINATIONS

1701. Scope of Authority

Section 1702 sets forth the procedures to be followed for Registered Entities to challenge determinations made by Planning Coordinators under Reliability Standard PRC-023. Section 1703 sets forth the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

1702. Challenges to Determinations by Planning Coordinators Under Reliability Standard PRC-023

1. This Section 1702 establishes the procedures to be followed when a Registered Entity wishes to challenge a determination by a Planning Coordinator of the sub-200 kV circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers (defined as "Registered Entities" for purposes of this Section 1702) must comply with the requirements of Reliability Standard PRC-023.

2. Planning Coordinator Procedures

    2.1 Each Planning Coordinator shall establish a procedure for a Registered Entity to submit a written request for an explanation of a determination made by the Planning Coordinator under PRC-023.

    2.2 A Registered Entity shall follow the procedure established by the Planning Coordinator for submitting the request for explanation and must submit any such request within 60 days of receiving the determination under PRC-023 from the Planning Coordinator.

    2.3 Within 30 days of receiving a written request from a Registered Entity, the Planning Coordinator shall provide the Registered Entity with a written explanation of the basis for its determination under PRC-023, unless the Planning Coordinator provided a written explanation of the basis for its determination when it initially informed the Registered Entity of its determination.

3. A Registered Entity may challenge the determination of the Planning Coordinator by filing with the appropriate Regional Entity, with a copy to the Planning Coordinator, within 60 days of receiving the written explanation from the Planning Coordinator. The challenge shall include the following: (a) an explanation of the technical reasons for its disagreement with the Planning Coordinator's determination, along with any supporting documentation, and (b) a copy of the Planning Coordinator's written explanation. Within 30 days of receipt of a challenge, the Planning Coordinator may file a response to the Regional Entity, with a copy to the Registered Entity.

4. The filing of a challenge in good faith shall toll the time period for compliance with PRC-023 with respect to the subject facility until such time as the challenge is withdrawn, settled or resolved.

5. The Regional Entity shall issue its written decision setting forth the basis of its determination within 90 days after it receives the challenge and send copies of the decision to the Registered Entity and the Planning Coordinator. The Regional Entity may convene a meeting of the involved entities and may request additional information. The Regional Entity shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

6. A Planning Coordinator or Registered Entity affected by the decision of the Regional Entity may, within 30 days of the decision, file an appeal with NERC, with copies to the Regional Entity and the Planning Coordinator or Registered Entity. The appeal shall state the basis of the objection to the decision of the Regional Entity and shall include the Regional Entity decision, the written explanation of the Planning Coordinator's determination under PRC-023, and the documents and reasoning filed by the Registered Entity with the Regional Entity in support of its objection. The Regional Entity, Planning Coordinator or Registered Entity may file a response to the appeal within 30 days of the appeal.

7. The Board of Trustees shall appoint a panel to decide appeals from Regional Entity decisions under Section 1702.5. The panel, which may contain alternates, shall consist of at least three appointees, one of whom must be a member of the NERC staff, who are knowledgeable about PRC-023 and transmission planning and do not have a direct financial or business interest in the outcome of the appeal. The panel shall decide the appeal within 90 days of receiving the appeal from the decision of the Regional Entity and shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

8. The Planning Coordinator or Registered Entity affected by the decision of the panel may request that the Board of Trustees review the decision by filing its request for review and a statement of reasons with NERC's Chief Reliability Officer within 30 days of the panel decision. The Board of Trustees may, in its discretion, decline to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. Within 90 days of the request for review under this Section 1702.8, the Board of Trustees may either (a) issue a decision on the merits, which shall be the final NERC decision, or (b) issue a notice declining to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. If no written decision or notice declining review is issued within 90 calendar days, the appeal shall be deemed to have been denied by the Board of Trustees and this will have the same effect as a notice declining review.

9. The Registered Entity or Planning Coordinator may appeal the final NERC decision to the Applicable Governmental Authority within 30 days of receipt of

the Board of Trustees' final decision or notice declining review, or expiration of the 90-day review period without any action by NERC.

10. The Planning Coordinator and Registered Entity are encouraged, but not required, to meet to resolve any dispute, including use of mutually agreed to alternative dispute resolution procedures, at any time during the course of the matter. In the event resolution occurs after the filing of a challenge, the Registered Entity and Planning Coordinator shall jointly provide to the applicable Regional Entity a written acknowledgement of withdrawal of the challenge or appeal, including a statement that all outstanding issues have been resolved.

1703. Challenges to NERC Determinations of BES Exception Requests Under Section 509

1. This Section 1703 establishes the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

2. A Submitting Entity (or Owner if different) aggrieved by the decision of NERC to approve or disapprove an Exception Request or to terminate an Exception with respect to any Element may, within 30 days following the date of the decision, file a written challenge to the decision with the NERC director of compliance operations, with copies to the Regional Entity and the Submitting Entity or Owner if different. The challenge shall state the basis of the objection to the decision of NERC. The Regional Entity, and the Submitting Entity or Owner if different, may file a response to the challenge within 30 days following the date the challenge is filed with NERC.

3. The challenge shall be decided by the Board of Trustees Compliance Committee. Within 90 days of the date of submission of the challenge, the Board of Trustees Compliance Committee shall issue its decision on the challenge. The decision of the Board of Trustees Compliance Committee shall be the final NERC decision; provided, that the Board of Trustees Compliance Committee may extend the deadline date for its decision to a date more than 90 days following submission of the challenge, by issuing a notice to the Submitting Entity, the Owner (if different) and the Regional Entity stating the revised deadline date and the reason for the extension.

4. The Submitting Entity, or Owner if different, may appeal the final NERC decision to, or seek review of the final NERC decision by, the Applicable Governmental Authority(ies), in accordance with the legal authority and rules and procedures of the Applicable Governmental Authority(ies). Any such appeal shall be filed within thirty (30) days following the date of the decision of the Board of Trustees Compliance Committee, or within such other time period as is provided for in the legal authority, rules or procedures of the Applicable Governmental Authority.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. FA11-21-000**

COMPLIANCE FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] submits this compliance filing in accordance with the Commission's January 16, 2013 Order in Docket No. FA11-21-000.[2] In the January 16 Order, the Commission approved a Settlement Agreement between the Office of Enforcement ("Enforcement") and NERC related to Enforcement's findings and recommendations arising out of its 2012 performance audit of NERC. Specifically, Section II.7(b)(i) of the Settlement Agreement requires that:

> Within forty-five days of the end of each quarter, beginning with the quarter ending March 31, 2013, NERC will file with the Commission the unaudited report of the NERC budget-to-actual spending variances during the preceding quarter. This report will include information regarding sources and uses of operating and working capital reserves and will match or exceed the level of detail of the quarterly budget-to-actual variance report of NERC expenditures attached to the agenda of NERC Board of Trustees Finance and Audit Committee's October 2012 meeting.[3]

Attached hereto is the unaudited report of NERC's budget-to-actual variance information for the third quarter of 2018, in accordance with the January 16 Order. This variance information

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[1] NERC was certified by FERC as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006) ("ERO Certification Order").

[2] *See North American Electric Reliability Corporation, Order Approving Settlement Agreement*, 142 FERC ¶ 61,042 (2013) ("January 16 Order").

[3] *Id.*

was posted on NERC's website October 31, 2018 and reviewed at the November 6, 2018 open meeting of the NERC Finance and Audit Committee. The unaudited report was accepted by the NERC Board of Trustees at its meeting on November 7, 2018.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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III. DISCUSSION OF SIGNIFICANT VARIANCES BETWEEN 2018 BUDGET AND ACTUAL PROJECTED 2018 RESULTS

The attached third quarter 2018 variance report compares actual (unaudited) financial results to NERC's budgeted expenditures as of September 30, 2018, and projected year-end 2018 financial results to NERC's total 2018 budgeted expenditures. NERC is providing additional discussion of significant variances between the projected (unaudited) year-end 2018 results and NERC's 2018 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 2018 results and the 2018 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. Fixed Asset Additions

Fixed asset additions are $2.0 million (68.7%) under budget as of September 30, 2018, due to timing differences of expenditures and lower than budgeted spending. Fixed asset additions are projected to be under budget at year-end by $533,342 (13.8%), primarily in the IT Department to manage overall department costs to the annual budget. No single variance item in the IT Department is projected to exceed $500,000 for the year, nor will funds be redirected to any specific project or major activity that exceeds $500,000.

IV. CONCLUSION

NERC respectfully requests that the Commission accept this filing as compliant with Section II.7(b)(i) of the Settlement Agreement and the Commission's January 16 Order in Docket No. FA11-21-000.

Respectfully submitted,

/s/ Meredith M. Jolivert

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Counsel for North American Electric Reliability Corporation

Dated: November 14, 2018

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 November, 2018.

/s/ Meredith M. Jolivert

Meredith M. Jolivert
Counsel for North American Electric Reliability Corporation

ATTACHMENT

Summary of Unaudited Results
For the Month Ending September 30, 2018

Table of Contents

		Page
I.	Executive Summary	
	▪ Projected Year-End Results	2
	▪ Year-to-Date Actual Results	3
II.	Detailed Operating Results	
	▪ Variances by Revenue and Expense Category	4
	▪ Variances by Department / Program	6
III.	Supplemental Schedules	
	▪ Schedule 1 – Reserves	8
	▪ Schedule 2 – IT Projects	9
	▪ Schedule 3 – E-ISAC & CRISP	12

Executive Summary

Projected Year-End Results
($ millions)

FUNDING	Projected	Budget	Over (Under)
Revenues	$ 72.5	$ 72.4	$ 0.1
Funding from Reserves			
Assessment Stabilization Reserve	0.6	0.6	-
TOTAL FUNDING	**$ 73.1**	**$ 73.0**	**$ 0.1**
EXPENDITURES			
Expenses (excluding Depreciation)	$ 70.3	$ 69.3	$ 1.0
Fixed Asset Additions	3.3	3.9	(0.6)
TOTAL EXPENDITURES	**$ 73.6**	**$ 73.2**	**$ 0.4**
RESERVE INCREASE (DECREASE)	**$ (0.5)**	**$ (0.2)**	**$ (0.3)**

FUNDING

- Revenues
  - Projected to be close to budget at year-end. Interest income and workshop fees are projected to be above budget, while testing fee income and CRISP revenues are expected to be below budget.

EXPENDITURES

- Expenses (excluding depreciation)
  - Personnel expenses expected to be over budget primarily due to increased medical insurance costs and search fees, and are partially offset by lower retirement costs.
  - Contracts and consultants projected to be over budget primarily due to costs for SPP RE transition work, and a cyber-security supply chain risk study.
  - Office costs projected to be over budget due to higher software license, support, and hosting expense.
- Fixed Assets
  - Projected to be below budget at year-end due to anticipated lower spending in IT to manage overall department costs to the annual budget.

RESERVE INCREASE (DECREASE)

- Projected decrease in total reserves is $0.5M versus a budgeted decrease of $0.2M.

Year-to-Date Actual Results
($ millions)

FUNDING	Actual	Budget	Over (Under)
Revenues	$ 54.4	$ 54.3	$ 0.1
Funding from Reserves			
Assessment Stabilization Reserve	0.6	0.6	-
TOTAL FUNDING	**$ 55.0**	**$ 54.9**	**$ 0.1**
EXPENDITURES			
Expenses (excluding Depreciation)	$ 50.7	$ 52.2	$ (1.5)
Fixed Asset Additions	0.9	2.9	(2.0)
TOTAL EXPENDITURES	**$ 51.6**	**$ 55.1**	**$ (3.5)**
RESERVE INCREASE (DECREASE)	**$ 3.4**	**$ (0.2)**	**$ 3.6**

FUNDING

- Revenues
  - Interest income and workshops are over budget year-to-date, which is offset by lower than budgeted testing fee revenue.

EXPENDITURES

- Expenses (excluding depreciation)
  - Contracts and Consultants, Office Costs, and Professional Services are under budget due to the expected timing of expenditures versus budget.
- Fixed Assets
  - Under budget due to the expected timing of expenditures and lower than budgeted spending in IT.

OPERATING RESERVE INCREASE (DECREASE)

- Reserve increase higher than budget by $3.6 million
  - Additional net increase of reserves from operating results, primarily due to the expected timing of expenditures versus budget, and anticipated lower spending in IT to manage overall department costs to the annual budget.

Detailed Operating Results

Total NERC (including CRISP)

Variances by Revenue and Expense Category

	YTD Actual	YTD Budget	YTD Over (Under)	% Inc (Dec)	Annual Projection	Annual Budget	Annual Over (Under)	% Inc (Dec)
TOTAL FUNDING	**$ 54,982,092**	**$ 54,892,166**	**$ 89,926**	**0.2%**	**$ 73,107,152**	**$ 72,981,221**	**$ 125,931**	**0.2%**
EXPENDITURES								
Personnel	$ 30,987,867	$ 31,030,004	$ (42,137)	(0.1%)	$ 41,399,667	$ 40,969,105	$ 430,562	1.1%
Meetings, Travel, and Conference Calls	2,521,391	2,555,700	(34,309)	(1.3%)	3,481,777	3,395,100	86,677	2.6%
Contracts and Consultants	9,239,784	10,215,458	(975,674)	(9.6%)	14,039,122	13,724,185	314,937	2.3%
Rent and Facilities	2,198,298	2,318,853	(120,555)	(5.2%)	3,038,960	3,091,804	(52,844)	(1.7%)
Office Costs, Professional, and Misc.*	5,669,165	5,962,011	(292,846)	(4.9%)	8,190,897	7,942,084	248,813	3.1%
Other Non-Operating Expenses	74,016	104,159	(30,143)	(28.9%)	149,171	138,878	10,293	7.4%
Fixed Asset Additions*	908,455	2,905,500	(1,997,045)	(68.7%)	3,340,658	3,874,000	(533,342)	(13.8%)
TOTAL EXPENDITURES	**$ 51,598,976**	**$ 55,091,684**	**$ (3,492,707)**	**(6.3%)**	**$ 73,640,254**	**$ 73,135,156**	**$ 505,098**	**0.7%**
RESERVE INCREASE (DECREASE)	**$ 3,383,116**	**$ (199,518)**	**$ 3,582,634**	**(1795.6%)**	**$ (533,102)**	**$ (153,935)**	**$ (379,167)**	**246.3%**
FTEs	**189.7**	**199.3**	**(9.6)**	**(4.8%)**	**191.9**	**199.3**	**(7.4)**	**(3.7%)**

***** Excludes depreciation expense

Following is a brief summary of variances by major categories:

- Personnel Expense
  - Year-to-date actuals are slightly under budget, and annual projection is over budget due to higher than expected medical insurance costs and search fees.

- Contracts and Consultants Expense
  - Under budget year-to-date because of the expected timing of expenditures versus budget.
  - Projected to be over budget primarily due to costs for SPP RE transition work, and a cyber-security supply chain risk study (see table below).

CONTRACTS and CONSULTANTS	YTD Actual	YTD Budget	YTD Over (Under)	Annual Projection	Annual Budget	Annual Over (Under)
Reliability Standards	$ 100,000	$ -	$ 100,000	$ 100,000	$ -	$ 100,000
Compliance Assurance	32,944	37,500	(4,556)	53,750	50,000	3,750
Compliance Analysis, Registration and Certification	-	-	-	-	-	-
Compliance Enforcement	42,131	-	42,131	48,500	-	48,500
Reliability Assessment and System Analysis	142,500	393,750	(251,250)	370,000	525,000	(155,000)
Reliability Risk Management	1,476,591	1,542,963	(66,372)	1,938,475	1,867,525	70,950
E-ISAC	739,865	825,150	(85,285)	1,200,000	1,100,200	99,800
Training, Education, and Personnel Certification	222,468	449,175	(226,707)	552,900	598,900	(46,000)
General and Administrative and Executive	41,000	-	41,000	80,000	80,000	-
Legal and Regulatory	-	-	-	-	-	-
Policy and External Affairs	14,225	16,250	(2,025)	41,500	20,000	21,500
Information Technology	1,438,428	1,592,975	(154,547)	2,345,403	2,123,966	221,437
Human Resources	365,173	318,750	46,423	590,000	640,000	(50,000)
Finance and Accounting	265,437	320,250	(54,813)	427,000	427,000	-
TOTAL (excluding CRISP)	**$ 4,880,762**	**$ 5,496,762**	**$ (616,000)**	**$ 7,747,528**	**$ 7,432,591**	**$ 314,937**
CRISP	4,359,022	4,718,696	(359,674)	6,291,594	6,291,594	-
TOTAL (including CRISP)	**$ 9,239,784**	**$ 10,215,458**	**$ (975,674)**	**$ 14,039,122**	**$ 13,724,185**	**$ 314,937**

- Office Costs and Professional Fees
  - Under budget year-to-date because of the expected timing of expenditures versus budget.
  - Projected to be slightly over budget at year-end due to higher than budgeted software license, support, and hosting expense.

- Fixed Asset Additions (excluding depreciation)
  - Under budget year-to-date because of the expected timing of expenditures versus budget.
  - Projected to be below budget at year-end due to anticipated lower spending in IT.

Variances by Department / Program

DIRECT EXPENSES and NET FIXED ASSETS	YTD Actual	YTD Budget	YTD Over (Under)	Annual Projection	Annual Budget	Annual Over (Under)
Reliability Standards	$ 2,218,671	$ 2,499,492	$ (280,821)	$ 2,974,652	$ 3,293,666	$ (319,014)
Compliance Assurance	3,632,716	3,393,859	238,857	4,887,804	4,520,550	367,254
Compliance Analysis, Registration and Certification	1,711,511	2,077,528	(366,017)	2,545,486	2,748,762	(203,277)
Compliance Enforcement	2,675,020	2,936,977	(261,957)	4,264,044	3,894,123	369,921
Reliability Assessment and System Analysis	2,998,707	3,112,336	(113,629)	4,024,436	4,105,476	(81,040)
Reliability Risk Management	5,960,212	5,928,267	31,945	7,921,198	7,654,264	266,934
E-ISAC	4,772,762	5,546,793	(774,031)	7,004,448	7,357,222	(352,774)
Training, Education, and Personnel Certification	972,083	1,291,585	(319,502)	1,505,994	1,706,574	(200,580)
General and Administrative and Executive	5,639,205	5,880,043	(240,838)	7,939,879	7,874,321	65,558
Legal and Regulatory	2,164,118	2,206,653	(42,535)	2,982,211	2,914,377	67,834
Policy and External Affairs	1,838,596	1,682,005	156,591	2,477,470	2,221,826	255,643
Information Technology	7,802,739	8,482,738	(679,999)	11,507,268	11,266,626	240,643
Human Resources	999,820	1,122,224	(122,404)	1,657,004	1,704,459	(47,455)
Finance and Accounting	3,197,698	3,026,411	171,287	4,255,166	4,008,326	246,839
TOTAL (excluding CRISP)	**$ 46,583,858**	**$ 49,186,910**	**$ (2,603,052)**	**$ 65,947,060**	**$ 65,270,572**	**$ 676,488**
CRISP	5,015,118	5,904,773	(889,655)	7,693,193	7,864,584	(171,390)
TOTAL EXPENSES and NET FIXED ASSETS	**$ 51,598,976**	**$ 55,091,684**	**$ (3,492,707)**	**$ 73,640,254**	**$ 73,135,156**	**$ 505,098**

- Reliability Standards: Under budget year-to-date and projected to be under budget primarily due to reduced personnel costs resulting from the reallocation of resources to other departments.

- Compliance Assurance: Over budget year-to-date and projected to be over budget mainly because of additional personnel costs resulting from the reallocation of resources from other departments.

- Compliance Analysis, Registration and Certification: Under budget year-to-date and projected to be under budget largely due to reduced personnel costs resulting from the reallocation of resources to other departments.

- Compliance Enforcement: Under budget year-to-date mainly due to the expected timing of CMEP technology project expenditures versus budget. Projected to be over budget primarily because of personnel and SPP RE transition costs.

- Reliability Risk Management: Projected to be over budget due to personnel and workshop meeting expenses, which is partially offset by increased revenues from workshop fees due to higher than budgeted conference attendance.

- E-ISAC: Under budget year-to-date largely because of decreased personnel costs due to lower FTEs and the expected timing of expenditures versus budget. Projected to be under budget at year-end because of lower than expected personnel costs.

- Training, Education, and Personnel Certification: Under budget year-to-date and projected to be under budget primarily because of reduced personnel costs resulting from lower than budgeted FTEs, as well as lower than budgeted testing fee revenue.

- Policy and External Affairs: Projected to be over budget at year-end because of higher personnel costs related to lower than budgeted attrition.

- Information Technology: Under budget year-to-date mainly due to the expected timing of expenditures versus budget. Projected to be over budget by year-end due to SPP RE transition costs.

- Finance and Accounting: Projected to be over budget at year-end largely due to higher personnel costs related to lower than budgeted attrition.

- CRISP: Under budget year-to-date mainly due to the expected timing of expenditures versus budget. Projected to be under by year-end because of lower than budgeted office costs.

SUPPLEMENTAL SCHEDULE 1

Year-End Projected Reserves

Reserve Account	Beginning Balance [2]	Budgeted Funding	Budgeted Uses	Other Funding (Uses) [1]	Net Financing Activity [3]	Expected Ending Balance
Operating Contingency	**$ 3,680,094**	$ 600,000	$ (231,393)	$ (964,996)	$ 714,726	**$ 3,798,431**
Future Obligations	**3,015,787**	-	(480,457)	(15,759)	-	**2,519,571**
Assessment Stabilization	**2,671,000**	-	(600,000)	-	-	**2,071,000**
System Operator	**477,484**	77,458	-	(14,171)	-	**540,771**
CRISP	**500,000**	-	-	-	-	**500,000**
Total Reserves	**$ 10,344,365**	$ 677,458	$ (1,311,850)	$ (994,926)	$ 714,726	**$ 9,429,773**

NOTES:

(1) 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.

(2) Some 2018 beginning balances have been adjusted from the 12/31/2017 variance report balances as the result of a reconciliation to the final audited balance sheet.

(3) Net Financing Activity is projected to be favorable to budget by $483k due to lower debt service requirements in 2018, primarily as a result of no capital borrowing in 2017.

SUPPLEMENTAL SCHEDULE 2

IT Projects

Projects in Progress	Project Budget [1]	Actual Spend	Expected Spend	Expected Over (Under) Budget
CMEP Technology Project	$ 5,103,000	$ 882,338	$ 5,103,000	$ -
E-ISAC Portal Enhancements	743,475	548,508	743,475	-
Entity Registration	600,000	139,472	600,000	-
CFR Enhancements	113,000	-	113,000	-
SPP RE Transition	-	335,652	484,637	484,637

Projects Completed in 2018	Project Budget [1]	Actual Spend	Actual Over (Under) Budget
NERC.com Phase 2	$ 300,000	$ 281,530	$ (18,471)
E-ISAC Document Management	215,000	215,000	-

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 and reflect only external (consultant) costs of the projects.*

SUPPLEMENTAL SCHEDULE 2

(continued)

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).

E-ISAC Portal Enhancements

(Started Jan 2018/ Planned Completion Dec 2018)

As requested by and prioritized by the Member Executive Committee (MEC), certain enhancements will be made to the E-ISAC portal during 2018 related to areas such as email notifications, user communities, and STIX-TAXII.

Entity Registration

(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.

CFR Enhancements

(Started Sep 2018/ Planned Completion Dec 2018)

This project is an enhancement to the Coordinated Functional Requirement (CFR) functionality, which is going to update the standard requirements that appear in the system, as well as performance improvement.

SPP RE Transition

(Started Mar 2018 / Planned Completion Oct 2018)

With SPP RE dissolving, NERC is assessing the changes required to applications that contain SPP RE data and the reassignment/classification of such information. The inventory will require 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 SPP RE to MRO and SERC.

NERC.com Phase 2

(Started May 2017 / Completed Feb 2018)

In response to feedback from stakeholders, this project was a first step to improve the usability and search capability of the public NERC.com website. The project also enhanced the stability of the NERC.com platform with a technology upgrade from SharePoint 2010 to SharePoint 2016 in Azure.

E-ISAC Document Management

(Started Apr 2018 / Completed Oct 2018)

NERC launched the Document Management Program to provide a secure and efficient method of creating, collaborating, storing, and disseminating the vast amount of information produced at NERC. The E-ISAC was the final business unit to be implemented.

SUPPLEMENTAL 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	$ 10,723,144	$ 14,297,524	$ 14,297,524	$ -
Other Funding	5,715,686	7,614,497	7,553,073	61,424
TOTAL FUNDING	$ 16,438,830	$ 21,912,022	$ 21,850,597	$ 61,424
EXPENDITURES				
Personnel Expense	$ 3,964,778	$ 5,558,855	$ 6,004,182	$ (445,326)
Meeting Expense	342,130	493,589	418,000	75,589
Operating Expenses (excluding Depreciation)	5,480,972	8,395,198	8,549,624	(154,427)
Fixed Assets (including Allocations)	(283,957)	9,981	359,377	(349,395)
Indirect Expenses	4,370,493	6,203,111	6,519,415	(316,304)
TOTAL EXPENDITURES	$ 13,874,415	$ 20,660,734	$ 21,850,597	$ (1,189,864)
RESERVE INCREASE (DECREASE)	$ 2,564,415	$ 1,251,288	$ 0	$ 1,251,288

SUPPLEMENTAL SCHEDULE 3

(continued)

CRISP

FUNDING	YTD Actual	Annual Projection	Annual Budget	Projected Over (Under)
Assessments	$ 1,028,826	$ 1,371,768	$ 1,371,768	$ -
Other Funding	5,567,042	7,261,770	7,348,144	(86,375)
TOTAL FUNDING	$ 6,595,868	$ 8,633,537	$ 8,719,912	$ (86,375)
EXPENDITURES				
Personnel Expense	$ 494,100	$ 949,451	$ 944,070	$ 5,381
Meeting Expense	58,658	72,818	48,000	24,818
Operating Expenses (excluding Depreciation)	4,462,360	6,570,925	6,772,514	(201,589)
Fixed Assets (including Allocations)	(39,038)	62,150	114,113	(51,963)
Indirect Expenses	600,847	978,193	841,215	136,978
TOTAL EXPENDITURES	$ 5,576,927	$ 8,633,537	$ 8,719,912	$ (86,375)
RESERVE INCREASE (DECREASE)	$ 1,018,941	$ 0	$ 0	$ 0

E-ISAC (excluding CRISP)

FUNDING	YTD Actual	Annual Projection	Annual Budget	Projected Over (Under)
Assessments	$ 9,694,318	$ 12,925,757	$ 12,925,757	$ -
Other Funding	148,644	352,728	204,929	147,799
TOTAL FUNDING	$ 9,842,962	$ 13,278,485	$ 13,130,686	$ 147,799
EXPENDITURES				
Personnel Expense	$ 3,470,678	$ 4,609,405	$ 5,060,112	$ (450,708)
Meeting Expense	283,472	420,771	370,000	50,771
Operating Expenses (excluding Depreciation)	1,018,612	1,824,273	1,777,110	47,163
Fixed Assets (including Allocations)	(244,919)	(52,169)	245,263	(297,433)
Indirect Expenses	3,769,645	5,224,918	5,678,200	(453,282)
TOTAL EXPENDITURES	$ 8,297,488	$ 12,027,197	$ 13,130,686	$ (1,103,489)
RESERVE INCREASE (DECREASE)	$ 1,545,474	$ 1,251,288	$ 0	$ 1,251,288

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Summary of Unaudited Results Third Quarter 2018

Andy Sharp, Controller
Finance and Audit Committee Meeting
November 6, 2018

RELIABILITY | ACCOUNTABILITY






2018 Third Quarter Results

- Total funding is on budget
  - Interest income is over budget, offset by lower testing fee revenue
- Total expenditures were $3.5M (6.3%) under budget
  - Primarily due to the expected timing of expenditures versus budget
- Net impact was $3.6M increase in operating reserves

2018 Year-End Projections

- NERC projecting to be on budget for funding
  - Interest income and workshop fees projected to be above budget, while testing fee income and CRISP revenues expected to be below budget
- NERC projecting to be slightly over budget for total expenditures ($400k or 0.7%)
  - Primarily costs associated with SPP RE dissolution activity
- Projected operating reserve usage of $500k, which is $300k over budget
- Net impact of financing activity (new borrowings and loan payments) is a $483k favorable variance to projected reserves

2018 Projected Year-End Reserves

- Total projected reserves balance is $9.4M
  - Operating Contingency Reserve (OCR) – $3.8M
  - Assessment Stabilization Reserve (ASR) – $2.1M
  - Future Obligation Reserve – $2.5M
  - System Operator Reserve – $541k
  - CRISP Reserve – $500k

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



Questions and Answers

165 FERC ¶ 61,023
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Neil Chatterjee,
and Richard Glick.

North American Electric Reliability Corporation Docket No. RR18-9-000

ORDER ACCEPTING 2019 BUSINESS PLANS AND BUDGETS

(Issued October 18, 2018)

1. On August 24, 2018, the North American Electric Reliability Corporation (NERC) filed 2019 business plans and budgets for NERC, each Regional Entity,[1] and the Western Interconnection Regional Advisory Body (WIRAB) (collectively, NERC Application). For the reasons discussed below, we accept the 2019 business plans and budgets of NERC, the Regional Entities, and WIRAB, as well as the associated attachments and updates, and authorize issuance of billing invoices to fund the fiscal year 2019 operations of NERC, the Regional Entities, and WIRAB.

I. Background

A. Regulatory History

2. Section 215 of the Federal Power Act (FPA) requires the Commission to certify an Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability

[1] The seven Regional Entities are: Florida Reliability Coordinating Council; Midwest Reliability Organization; Northeast Power Coordinating Council, Inc.; ReliabilityFirst Corporation; SERC Reliability Corporation; Texas Reliability Entity; and Western Electricity Coordinating Council (WECC).

Standards, subject to Commission review and approval.[2] In July 2006, the Commission certified NERC as the ERO.[3]

3. Section 215(c)(2)(B) of the FPA provides that the ERO must have rules that "allocate equitably reasonable dues, fees, and other charges among end users for all activities under this section."[4] On February 3, 2006, the Commission issued Order No. 672 to implement the requirements of section 215 of the FPA, which generally provides for Commission authorization of funding for "statutory" functions conducted by the ERO, the Regional Entities, and WIRAB (i.e., those functions carried out pursuant to section 215 of the FPA).[5] Among other things, Order No. 672 established requirements for funding the ERO and approval of an ERO business plan and budget.[6] Moreover, the Commission's regulations require the ERO to file with the Commission the ERO's proposed annual budget for statutory and non-statutory activities 130 days before the beginning of the ERO's fiscal year.[7] Further, the ERO's filing must contain the annual budgets of each Regional Entity for statutory and non-statutory activities and provide supporting materials, including the ERO's and each Regional Entity's complete business plan and budget and organizational chart. The filing must also explain the proposed collection of all dues, fees, and charges, as well as the proposed expenditure of funds collected.

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[2] 16 U.S.C. § 824o (2012).

[3] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030, *order on clarification and reh'g*, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[4] 16 U.S.C. § 824o(c)(2)(B).

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

[6] Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 197.

[7] 18 C.F.R. § 39.4(b) (2018).

B. NERC Application

4. The NERC Application contains NERC's proposed business plan and budget for the year ending December 31, 2019, as well as the proposed business plans and budgets of each of the seven Regional Entities and WIRAB for the year ending December 31, 2019.

5. NERC states that it prepared its 2019 business plan and budget, and worked with the Regional Entities in developing their business plans and budgets, through a rigorous process that provided ample opportunity for review and input by the NERC Board of Trustees Finance and Audit Committee and stakeholders. According to NERC, successive versions of the 2019 business plans and budgets were discussed by the Finance and Audit Committee as well as the full NERC Board of Trustees, in meetings and conference calls, with each event providing opportunities for stakeholders to comment.[8]

6. NERC states that the proposed assessment for the total ERO (i.e., NERC, the Regional Entities, and WIRAB) for 2019 allocable to the United States is $165,944,381, which includes $62,466,508 for NERC funding; $102,848,341 for Regional Entity funding; and $629,532 for WIRAB funding.[9] NERC explains that it will continue to allocate costs to end users in the United States based on net energy for load. NERC maintains that its proposed total United States net funding requirement for the ERO enterprise is equivalent to $0.0000417 per kWh, based on the aggregate net energy for load of the United States in 2017.[10]

7. In addition to the NERC, Regional Entity, and WIRAB business plans and budgets, the NERC Application contains various attachments including: NERC Management's Responses to Stakeholder Comments Submitted on Drafts of NERC's 2019 Business Plan and Budget (Attachment 11); Calculation of Adjustments for the Alberta Electric System Operator, Ontario Independent Electric System Operator, New Brunswick, and Québec2019 NERC Assessments (Attachment 12); Metrics Comparing Regional Entity Operations Based on the 2019 Budgets (Attachment 13); Metrics on NERC and Regional Entity Administrative (Indirect) Costs Based on the 2018 and 2019 Budgets (Attachment 14); and Report of Board of Trustees Remuneration Review (Attachment 15).

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[8] NERC Application at 3-4.

[9] *Id.*, Attachment 1 (Summary Tables for NERC and Regional Entity Proposed 2019 Budgets and Assessments) at 2.

[10] *Id.* at 26.

II. Notice and Responsive Pleadings

8. Notice of NERC's August 24, 2018 filing was published in the *Federal Register*, 83 Fed. Reg. 44,616 (2018), with interventions and protests due on or before September 14, 2018. No interventions or protests were filed.

III. Discussion

A. NERC Business Plan and Budget

9. NERC states that its 2019 business plan and budget is based on the following program areas: (1) Reliability Standards; (2) Compliance Assurance, Compliance Analysis, Organization Registration and Certification, and Compliance Enforcement; (3) Reliability Assessment and System Analysis; (4) Reliability Risk Management, which is comprised of Situation Awareness, Event Analysis, and Performance Analysis; (5) Electricity Information Sharing and Analysis Center (E-ISAC), including the Cyber Risk Information Sharing Program (CRISP); and (6) Training, Education, and Personnel Certification.[11] For these program areas, NERC describes each program, identifies the program's goals and objectives, and provides the current number of full-time equivalent employees (FTEs), as well as the FTEs budgeted for 2019. NERC also provides 2018 accepted budget data and 2018 year-end projected data for comparison to the 2019 proposed budget data.

10. NERC's proposed total funding requirement for 2019 is $79,130,349, which is an increase of $6,149,128 (8.4 percent) over NERC's 2018 total funding requirement of $72,981,221.[12] NERC states that its 2019 budget, excluding E-ISAC costs, of $52,654,028 is 2.7 percent higher than its 2018 budget excluding E-ISAC costs.[13] NERC's proposed 2019 net funding requirement is $68,883,995 (i.e., the total funding requirement less $10,246,354[14] in funding from other sources), of which $62,466,508 is allocated to the United States.[15]

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[11] *Id.* at 7-8.

[12] *Id.* at 16, Attachment 2 at 10.

[13] *Id.* at 15-16.

[14] *Id.* at 17. NERC's other funding sources are penalty payments, third-party funding for CRISP, revenue from services and software, testing and workshop fees, and interest. *Id.* at 16.

[15] *Id.*, Attachment 1 at 2.

11. NERC notes that the 2019 budget for the E-ISAC, including funding for CRISP, is 25.4 percent higher than its 2018 budget.[16] NERC explains that the E-ISAC budget reflects increased computer and software capital expenditures as well as the addition of 8.46 FTEs. NERC states that these increases in the E-ISAC budget will support NERC's long term strategy for the E-ISAC, as explained in detail in Exhibit E of its business plan and budget.[17]

12. NERC states that the proposed 2019 business plan and budget reflects a provision for working capital and operating reserve funding in the amount of $148,674.[18] Finally, NERC proposes a 2019 staffing level of 204.92 FTEs, an increase of 5.64 FTEs from 2018 budget staffing levels.[19]

13. NERC states that it received $500,000 in penalty monies for the period of July 1, 2017 through June 30, 2018.[20] In accordance with the Commission's June 18, 2015 order,[21] and pursuant to section 1107.4 of the NERC Rules of Procedure, NERC requests an exception to section 1107.2 of the NERC Rules of Procedure to permit it to deposit the $500,000 of penalty monies into its assessment stabilization reserve. NERC also requests approval to use $550,000 of funds from the assessment stabilization reserve to reduce 2019 assessments. NERC states that these actions will leave a balance of $1,521,000 in the assessment stabilization reserve for use to offset and stabilize assessments in future years' budgets.[22]

Commission Determination

14. We accept NERC's 2019 business plan and budget. We find that NERC's 2019 budget is reasonable and that the associated costs of NERC's jurisdictional functions are equitably allocated among end users in the United States. Additionally, based on the details provided by NERC in its application, we grant NERC's request for an exception under

[16] *Id.* at 33. NERC notes that CRISP comprises 33.0 percent of the total E-ISAC budget.

[17] *Id.*, Attachment 2 at 11; Attachment 2, Exhibit E.

[18] *Id.* at 16.

[19] *Id.* at 17, Attachment 2 at 10.

[20] *Id.* at 40.

[21] *North American Electric Reliability Corp.*, 151 FERC ¶ 61,225, at P 19 (2015).

[22] NERC Application at 39-40.

section 1107 of the NERC Rules of Procedure, allowing NERC to allocate $500,000 in penalty monies to its assessment stabilization reserve, and approve the withdrawal of $550,000 from the assessment stabilization reserve (i.e., a net withdrawal of $50,000). We note that the decision here is limited to this case. The Commission will address any future requests for an exception to section 1107.2 of the NERC Rules of Procedure based on the facts at that time.

B. Regional Entity Business Plans and Budgets

15. The NERC Application includes the 2019 business plans and budgets of each Regional Entity. The proposed total assessment for the Regional Entities that is allocable to the United States is $102,848,341, which represents a $1,696,411 (1.62 percent) decrease from 2018.[23] NERC states that it reviewed the Regional Entity business plans and budgets and concludes that each Regional Entity proposes necessary and adequate resources to carry out its delegated functions.[24]

Commission Determination

16. We find that each Regional Entity submission reasonably supports the level of expenditures identified in their respective budgets and that each Regional Entity is focused on adequately staffing and funding all of their respective program areas to perform the delegated, statutory functions. Accordingly, we accept the Regional Entity business plans and budgets.

C. WIRAB Business Plan and Budget

17. WIRAB proposes statutory expenses of $1,162,700 in 2019, which is a $94,915 (8.9 percent) increase from its 2018 budget.[25] To fund its operations in 2019, WIRAB proposes a statutory assessment of $750,000, of which $629,532 would be allocable to end users in the United States.[26]

18. The NERC Application indicates that WIRAB's proposed key activities in 2019 include the following: (1) working with WECC and NERC to ensure that all Reliability Coordinators in the Western Interconnection work cooperatively and in the public interest to coordinate outages, study seams issues, and share information to maintain or improve the

[23] NERC Application, Attachment 1 at 2.

[24] *Id.* at 44.

[25] *Id.* at 61.

[26] *Id.* at 61-62.

overall reliability of the bulk electric system; (2) advising WECC on the implications of high levels of distributed solar photovoltaic deployment on the reliable operation of the bulk electric system; (3) encouraging WECC to systematically perform reliability assessments evaluating the availability of essential reliability services under a wide range of future resource scenarios; and (4) encouraging WECC to share key findings and insights from its event analysis and situational awareness program in public briefings with Western policymakers and regulators in an effort to increase awareness of the causes of system events and the actions that can be taken to prevent recurrences of the events.[27] WIRAB's budget includes 5.0 FTEs for 2019, which is 0.5 FTEs less than in its 2018 budget.[28]

Commission Determination

19. Based on the information provided in the instant filing, we conclude that WIRAB's 2019 business plan and budget is reasonable and, accordingly, we accept WIRAB's 2019 business plan and budget.

The Commission orders:

(A) NERC's 2019 business plan and budget is hereby accepted.

(B) The Regional Entities' 2019 business plans and budgets are hereby accepted.

(C) WIRAB's 2019 business plan and budget is hereby accepted.

By the Commission. Chairman McIntyre was not present at the Commission Meeting held on October 18, 2018 and did not vote on this item.

(S E A L)

Kimberly D. Bose,
Secretary.

[27] *Id.*, Attachment 11 (Western Interconnection Regional Advisory Body Proposed 2019 Business Plan and Budget) at 9-14.

[28] *Id.*, Attachment 11 at 18.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

165 FERC ¶ 61,124
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket Nos. RM18-8-000 and RM15-11-003; Order No. 851]

Geomagnetic Disturbance Reliability Standard; Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events

(Issued November 15, 2018)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) approves Reliability Standard TPL-007-2 (Transmission System Planned Performance for Geomagnetic Disturbance Events). The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization, submitted Reliability Standard TPL-007-2 for Commission approval. The Commission also 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; and (2) to authorize extensions of time to implement corrective action plans on a case-by-case basis. In addition, the Commission accepts the revised GMD research work plan submitted by NERC.

EFFECTIVE DATE: This rule will become effective **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

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SUPPLEMENTARY INFORMATION:

20181115-3048 FERC PDF (Unofficial) 11/15/2018

165 FERC ¶ 61,124
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Cheryl A. LaFleur and Richard Glick.

Geomagnetic Disturbance Reliability Standard	Docket Nos. RM18-8-000
Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events	RM15-11-003

ORDER NO. 851

FINAL RULE

(Issued November 15, 2018)

1. Pursuant to section 215 of the Federal Power Act (FPA), the Commission approves Reliability Standard TPL-007-2 (Transmission System Planned Performance for Geomagnetic Disturbance Events).[1] The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted Reliability Standard TPL-007-2 for Commission approval in response to directives in Order No. 830.[2] As discussed in this final rule, we determine that Reliability Standard TPL-007-2 better addresses the risks posed by geomagnetic disturbances

[1] 16 U.S.C. 824o.

[2] *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, Order No. 830, 156 FERC ¶ 61,215, (2016) *reh'g denied*, Order No. 830-A, 158 FERC ¶ 61,041 (2017).

20181115-3048 FERC PDF (Unofficial) 11/15/2018

(GMDs) to the Bulk-Power System, particularly with respect to the potential impacts of locally-enhanced GMD events, than currently-effective Reliability Standard TPL-007-1 and complies with the Commission's directives in Order No. 830.

2. GMD events occur when the sun ejects charged particles that interact with and cause changes in the earth's magnetic fields. GMD events have the potential to cause severe, wide-spread impacts on the Bulk-Power System.[3] Currently-effective Reliability Standard TPL-007-1 requires applicable entities to assess the vulnerability of their transmission systems to a "benchmark GMD event." An applicable entity that does not meet certain performance requirements, based on the results of the benchmark GMD vulnerability assessment, must develop and implement a corrective action plan to achieve the performance requirements.

3. The improvements in Reliability Standard TPL-007-2 are responsive to the directives in Order No. 830: (1) to revise the benchmark GMD event definition, as it pertains to the required GMD vulnerability assessments and transformer thermal impact assessments, so that the definition is not based solely on spatially-averaged data; (2) to require the collection of necessary geomagnetically induced current (GIC) monitoring and magnetometer data; and (3) to include a one-year deadline for the completion of corrective action plans and two- and four-year deadlines to complete mitigation actions

[3] *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 143 FERC ¶ 61,147, at P 3, *reh'g denied*, 144 FERC ¶ 61,113 (2013); *see also* Reliability Standard TPL-007-2, Background.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

involving non-hardware and hardware mitigation.[4] As discussed below, Reliability Standard TPL-007-2 complies with these directives and improves upon the currently-effective version of the Reliability Standard by requiring applicable entities to: (1) in addition to the benchmark GMD event requirements, conduct supplemental GMD vulnerability assessments and thermal impact assessments, which apply a new supplemental GMD event definition that does not rely solely on spatially-averaged data; (2) obtain GIC and magnetometer data; and (3) meet the Commission-directed deadlines for the development and completion of tasks in corrective action plans. Accordingly, pursuant to section 215(d)(2) of the FPA, we approve Reliability Standard TPL-007-2.[5]

4. In addition, as discussed in the Notice of Proposed Rulemaking, we determine that it is appropriate, pursuant to section 215(d)(5) of the FPA,[6] to direct NERC to develop and submit modifications to Reliability Standard TPL-007-2 to require the development and completion of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities.[7] As discussed below, requiring corrective action plans for supplemental GMD event vulnerabilities is appropriate to ensure the reliability of the Bulk-Power

[4] "Spatial averaging" refers to the averaging of magnetometer readings over a geographic area. In developing the benchmark GMD event definition, the standard drafting team averaged several (but not all) geomagnetic field readings taken by magnetometers located within square geographical areas of 500 km per side.

[5] 16 U.S.C. 824o(d)(2).

[6] *Id.* 824o(d)(5).

[7] *Geomagnetic Disturbance Reliability Standard*, Notice of Proposed Rulemaking, 83 FR 23854 (May 23, 2018), 163 FERC ¶ 61,126 (2018) (NOPR).

20181115-3048 FERC PDF (Unofficial) 11/15/2018

System when confronted with locally-enhanced GMD events, just as corrective action plans are necessary to mitigate the effects of benchmark GMD events. Based on the record in this proceeding, we discern no technical barriers to either developing or complying with such a requirement. Moreover, the record supports issuance of a directive at this time notwithstanding comments in response to the NOPR advocating postponement of any directive until after the completion of additional GMD research. As discussed below, the relevant GMD research tasks are scheduled to be completed before the modified Reliability Standard must be submitted. The Commission directs NERC to submit the modified Reliability Standard for approval within 12 months from the effective date of Reliability Standard TPL-007-2.

5. We also determine that it is appropriate, pursuant to section 215(d)(5) of the FPA, to direct that NERC 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]." The NOPR raised concerns regarding the appropriateness of a self-executing deadline extension and observed that it was inconsistent with guidance in Order No. 830 that extension requests be considered on a case-by-case basis.[8] We recognize the point made in NERC's comments in response to the NOPR that, under NERC's proposal, "NERC and Regional Entity staff would exercise their authority to review the reasonableness of any Corrective Action Plan delay, including reviewing the 'situations

[8] Order No. 830, 156 FERC ¶ 61,215 at P 102.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

beyond the control of the responsible entity' that are cited as causing the delay" and that Requirement R7.4 is "not so flexible … as to allow entities to extend Corrective Action Plan deadlines indefinitely or for any reason whatsoever."[9] While we generally agree with the standard of review that NERC states it will use to assess the merits of extension requests, we conclude that such assessments should be made before any time extensions are permitted. By requiring prior approval of extension requests, the modified Reliability Standard will limit the potential for unwarranted delays in implementing corrective action plans while also providing NERC with an advance and more holistic understanding of where, to whom, and for how long, extensions are granted. We expect that the extension process developed by NERC in response to our directive will be timely and efficient such that applicable entities will receive prompt responses after submitting to NERC or a Regional Entity, as appropriate, the extension request and associated information described in Requirement R7.4.[10] We also direct NERC, as proposed in the NOPR, to prepare and submit a report addressing how often and why applicable entities are exceeding corrective action plan deadlines as well as the disposition of extension requests, which is due within 12 months from the date on which applicable entities must comply with the last requirement of Reliability Standard TPL-007-2. Following receipt of the report, the Commission will determine whether further action is necessary.

[9] NERC Comments at 20-21.

[10] NOPR, 163 FERC ¶ 61,126 at P 50.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

6. The Commission, as discussed below, also accepts the revised GMD research work plan submitted by NERC on April 19, 2018.[11]

I. Background

A. Section 215 and Mandatory Reliability Standards

7. Section 215 of the FPA requires the Commission to certify an ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Once approved, the Reliability Standards may be enforced in the United States by the ERO, subject to Commission oversight, or by the Commission independently.[12]

B. GMD Primer

8. GMD events occur when the sun ejects charged particles that interact and cause changes in the earth's magnetic fields.[13] Once a solar particle is ejected, it can take between 17 to 96 hours (depending on its energy level) to reach earth.[14] A geoelectric field is the electric potential (measured in volts per kilometer (V/km)) on the earth's surface and is directly related to the rate of change of the magnetic fields.[15] The geoelectric field has an amplitude and direction and acts as a voltage source that can

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[11] North American Electric Reliability Corporation, Filing, Docket No. RM15-11-003 (filed Apr. 19, 2018) (Revised GMD Research Work Plan).

[12] 16 U.S.C. 824o(e).

[13] *See* NERC, 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System at i-ii (February 2012).

[14] *Id.* at ii.

[15] *Id.*

20181115-3048 FERC PDF (Unofficial) 11/15/2018

cause GICs to flow on long conductors, such as transmission lines.[16] The magnitude of the geoelectric field amplitude is impacted by local factors such as geomagnetic latitude and local earth conductivity.[17] Geomagnetic latitude is the proximity to earth's magnetic north and south poles, as opposed to earth's geographic poles.[18] Local earth conductivity is the ability of the earth's crust to conduct electricity at a certain location to depths of hundreds of kilometers down to the earth's mantle. Local earth conductivity impacts the magnitude (i.e., severity) of the geoelectric fields that are formed during a GMD event by, all else being equal, a lower earth conductivity resulting in higher geoelectric fields.[19]

9. GICs can flow in an electric power system with varying intensity depending on the various factors discussed above. As explained in the Background section of Reliability Standard TPL-007-2, "[d]uring 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."

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[16] *Id.*

[17] NERC, Benchmark Geomagnetic Disturbance Event Description, Docket No. 15-11-000, at 4 (filed June 28, 2016) (2016 NERC White Paper).

[18] *Id.*

[19] *Id.*

20181115-3048 FERC PDF (Unofficial) 11/15/2018

C. Currently-Effective Reliability Standard TPL-007-1 and Order No. 830

1. Currently-Effective Reliability Standard TPL-007-1

10. Reliability Standard TPL-007-1 consists of seven requirements and applies to planning coordinators, transmission planners, transmission owners and generation owners who own or whose planning coordinator area or transmission planning area includes a power transformer with a high side, wye-grounded winding connected at 200 kV or higher.

11. Requirement R1 requires planning coordinators and transmission planners (i.e., "responsible entities") to determine the individual and joint responsibilities in the planning coordinator's planning area for maintaining models and performing studies needed to complete the GMD vulnerability assessment required in Requirement R4. Requirement R2 requires responsible entities to maintain system models and GIC system models needed to complete the GMD vulnerability assessment required in Requirement R4. Requirement R3 requires each responsible entity to have criteria for acceptable system steady state voltage performance for its system during the GMD conditions described in Attachment 1 of Reliability Standard TPL-007-1. Requirement R4 requires responsible entities to conduct a GMD vulnerability assessment every 60 months using the benchmark GMD event described in Attachment 1. Requirement R5 requires responsible entities to provide GIC flow information, based on the benchmark GMD event definition, to be used in the transformer thermal impact assessments required in Requirement R6, to each transmission owner and generator owner that owns an applicable transformer within the applicable planning area. Requirement R6 requires

20181115-3048 FERC PDF (Unofficial) 11/15/2018

transmission owners and generator owners to conduct thermal impact assessments on solely and jointly owned applicable transformers where the maximum effective GIC value provided in Requirement R5 is 75 Amperes per phase (A/phase) or greater. Requirement R7 requires responsible entities to develop corrective action plans if the GMD vulnerability assessment concludes that the system does not meet the performance requirements in Table 1 of Reliability Standard TPL-007-1.

12. Calculation of the benchmark GMD event, against which applicable entities must assess their facilities, is fundamental to compliance with Reliability Standard TPL-007-1. Reliability Standard TPL-007-1, Requirement R3 states that "[e]ach responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1."

13. Reliability Standard TPL-007-1, Attachment 1 states that the benchmark GMD event is composed of four elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) a scaling factor to account for local geomagnetic latitude; (3) a scaling factor to account for local earth conductivity; and (4) a reference geomagnetic field time series or wave shape to facilitate time-domain analysis of GMD impact on equipment. The product of the first three elements is referred to as the regional peak geoelectric field amplitude. The benchmark GMD event defines the geoelectric field values used to compute GIC flows

20181115-3048 FERC PDF (Unofficial) 11/15/2018

for a GMD vulnerability assessment, which is required in Reliability Standard TPL-007-1.[20]

14. For the purpose of determining a benchmark event that specifies what severity GMD events a responsible entity must assess for potential impacts on the Bulk-Power System, NERC determined that a 1-in-100 year GMD event would cause an 8 V/km reference peak geoelectric field amplitude at 60 degree north geomagnetic latitude using Québec's earth conductivity.[21] Scaling factors (i.e., multiplying values) are applied to this reference peak geoelectric field amplitude to adjust the 8 V/km value for different geomagnetic latitudes (scaling factors between 0.1 and 1.0) and earth conductivities (scaling factors between 0.21 and 1.17). NERC identified a reference geomagnetic field time series from an Ottawa, Ontario magnetic observatory during a 1989 GMD storm affecting Québec. NERC used this to estimate a time series (i.e., 10-second values over a period of days) of the geoelectric field that is representative of what is expected to occur at 60 degree geomagnetic latitude during a 1-in-100 year GMD event. Such a time series

[20] *See* Reliability Standard TPL-007-1, Requirements R4 and R5. Reliability Standard TPL-007-1 does not set a threshold amount of GIC flow that would constitute a vulnerable transformer. However, if a transformer is calculated to experience a maximum effective GIC flow during a benchmark GMD event of a least 75 A/phase, a thermal impact assessment of that transformer is required. *See* Reliability Standard TPL-007-1, Requirement R6.

[21] NERC used Québec as the location for the reference peak 1-in-100 year GMD event because of its proximity to 60 degree geomagnetic latitude and its well understood earth model. By creating scaling factors, each entity can scale this reference peak geoelectric field and geoelectric field time series values to match its own expected field conditions.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

is used in some methods of calculating the vulnerability of a transformer to damage from heating caused by GIC.

15. NERC used field measurements taken from the International Monitor for Auroral Geomagnetic Effects (IMAGE) magnetometer chain, which consists of 39 magnetometer stations in Northern Europe, for the period 1993-2013 to calculate the reference peak geoelectric field amplitude. As described in the 2016 NERC White Paper, to arrive at a reference peak geoelectric field amplitude of 8 V/km, NERC "spatially averaged" four different station groups each spanning a square area of approximately 500 km (roughly 310 miles) in width.

2. Order No. 830

16. On January 21, 2015, NERC submitted for Commission approval Reliability Standard TPL-007-1 in response to the directive in Order No. 779 that NERC develop one or more Reliability Standards to address the effects of GMD events on the electric grid.[22] In Order No. 830, the Commission approved Reliability Standard TPL-007-1, concluding that Reliability Standard TPL-007-1 addressed the Commission's directive by requiring applicable Bulk-Power System owners and operators to conduct, on a recurring five-year cycle, initial and ongoing vulnerability assessments regarding the potential impact of a benchmark GMD event on the Bulk-Power System as a whole and on Bulk-Power System components. In addition, the Commission determined that Reliability Standard TPL-007-1 requires applicable entities to develop and implement corrective

[22] Order No. 779, 144 FERC ¶ 61,113 at P 54.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

action plans to mitigate vulnerabilities identified through those recurring vulnerability assessments and that potential mitigation strategies identified in Reliability Standard TPL-007-1 include, but are not limited to, the installation, modification or removal of transmission and generation facilities and associated equipment.

17. In Order No. 830, the Commission also determined that Reliability Standard TPL-007-1 should be modified. Specifically, Order No. 830 directed NERC to develop and submit modifications to Reliability Standard TPL-007-1 concerning: (1) the calculation of the reference peak geoelectric field amplitude component of the benchmark GMD event definition; (2) the collection and public availability of necessary GIC monitoring and magnetometer data; and (3) deadlines for completing corrective action plans and the mitigation measures called for in corrective action plans. Order No. 830 directed NERC to develop and submit these revisions for Commission approval within 18 months of the effective date of Order No. 830.

18. With respect to the calculation of the reference peak geoelectric field amplitude component of the benchmark GMD event definition, Order No. 830 expressed concern with relying solely on spatial averaging in Reliability Standard TPL-007-1 because "the use of spatial averaging in this context is new, and thus there is a dearth of information or research regarding its application or appropriate scale."[23] While Order No. 830 directed that the peak geoelectric field amplitude should not be based solely on spatially-averaged data, the Commission indicated that this "directive should not be construed to prohibit the

[23] Order No. 830, 156 FERC ¶ 61,215 at P 45.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

use of spatial averaging in some capacity, particularly if more research results in a better understanding of how spatial averaging can be used to reflect actual GMD events."[24]

D. NERC Petition and Reliability Standard TPL-007-2

19. NERC states that Reliability Standard TPL-007-2 enhances currently-effective Reliability Standard TPL-007-1 by addressing reliability risks posed by GMDs more effectively and implementing the directives in Order No. 830.[25] NERC asserts that Reliability Standard TPL-007-2 reflects the latest in GMD understanding and provides a technically sound and flexible approach to addressing the concerns discussed in Order No. 830. NERC contends that the proposed modifications enhance reliability by expanding GMD vulnerability assessments to include severe, localized impacts and by implementing deadlines and processes to maintain accountability in the development, completion, and revision of corrective action plans developed to address identified vulnerabilities. Further, NERC states that the proposed modifications improve the availability of GMD monitoring data that may be used to inform GMD vulnerability assessments.

20. Reliability Standard TPL-007-2 modifies currently-effective Reliability Standard TPL-007-1 by requiring applicable entities to: (1) conduct supplemental GMD vulnerability and transformer thermal impact assessments in addition to the existing

[24] *Id.* P 46.

[25] Reliability Standard TPL-007-2 is not attached to this final rule. Reliability Standard TPL-007-2 is available on the Commission's eLibrary document retrieval system in Docket No. RM18-8-000 and on the NERC website, www.nerc.com.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

benchmark GMD vulnerability and transformer thermal impact assessments required in Reliability Standard TPL-007-1; (2) collect data from GIC monitors and magnetometers as necessary to enable model validation and situational awareness; and (3) develop necessary corrective action plans within one year from the completion of the benchmark GMD vulnerability assessment, include a two-year deadline for the implementation of non-hardware mitigation, and include a four-year deadline to complete hardware mitigation.[26]

21. In particular, Reliability Standard TPL-007-2 modifies Requirements R1 (identification of responsibilities), R2 (system and GIC system models) and R3 (criteria for acceptable System steady state) to extend the existing requirements pertaining to benchmark GMD assessments to the new supplemental GMD assessments. Reliability Standard TPL-007-2 adds the newly mandated supplemental GMD vulnerability and transformer thermal impact assessments in new Requirements R8 (supplemental GMD vulnerability assessment), R9 (GIC flow information needed for supplemental GMD thermal impact assessments) and R10 (supplemental GMD thermal impact assessments). The supplemental GMD event definition contains a higher, non-spatially-averaged reference peak geoelectric field amplitude component than the benchmark GMD event definition (12 V/km versus 8 V/km). These three new requirements largely mirror

[26] Unless otherwise indicated, the requirements of Reliability Standard TPL-007-2 are substantively the same as the requirements in currently-effective Reliability Standard TPL-007-1.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

existing Requirements R4, R5, and R6 that currently apply, and continue to apply, only to benchmark GMD vulnerability and transformer thermal impact assessments.[27]

22. In addition, Reliability Standard TPL-007-2 includes two other new requirements, Requirements R11 and R12, that require applicable entities to gather GIC monitoring data (Requirement R11) and magnetometer data (Requirement R12).

23. Reliability Standard TPL-007-2 modifies existing Requirement R7 (corrective action plans) to create a one-year deadline for the development of corrective action plans and two and four-year deadlines to complete actions involving non-hardware and hardware mitigation, respectively, for vulnerabilities identified in the benchmark GMD assessment. The modifications to Requirement R7 include a provision allowing for extension of deadlines if "situations beyond the control of the responsible entity determined in Requirement R1 prevent implementation of the [corrective action plan] within the timetable for implementation."

E. NOPR

24. On May 17, 2018, the Commission issued a NOPR that proposed to approve Reliability Standard TPL-007-2 as the Reliability Standard largely addresses the directives in Order No. 830. However, the NOPR identified two aspects of Reliability Standard TPL-007-2 that are inconsistent with Order No. 830: (1) the lack of any

[27] An exception is the qualifying threshold for transformers required to undergo thermal impact assessments: for the supplemental GMD assessment the qualifying threshold for transformers is a maximum effective GIC value of 85 A/phase while the threshold for benchmark GMD event assessments is 75 A/phase.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

requirement to develop and implement corrective action plans in response to assessed supplemental GMD event vulnerabilities; and (2) a general allowance, per proposed Requirement R7.4, of extensions of time to complete corrective action plans as opposed to permitting extensions of time on a case-by-case basis.

25. Having identified these issues, the NOPR proposed to direct NERC, pursuant to section 215(d)(5) of the FPA, to develop and submit modifications to Reliability Standard TPL-007-2 to require applicable entities to develop and implement corrective action plans to mitigate vulnerabilities discovered through supplemental GMD vulnerability assessments. The NOPR proposed to direct NERC to submit the modified Reliability Standard for approval within 12 months from the effective date of Reliability Standard TPL-007-2. The NOPR also sought comment on two options for addressing the Commission's concerns regarding the potential for undue delay of mitigation because of the proposed time-extension process in Requirement R7.4: (1) direct NERC to bring Reliability Standard TPL-007-2 into alignment with Order No. 830 through a process whereby NERC or Regional Entities consider extensions on a case-by-case basis using the information that must be submitted under Requirement R7.4; or (2) approve the proposed provision without directing modifications. Under either option, NERC would prepare and submit a report regarding how often and why applicable entities are exceeding corrective action plan deadlines following implementation of Reliability Standard TPL-007-2.[28]

[28] The NOPR proposed that the report, under the first option, would also include *(continued ...)*

20181115-3048 FERC PDF (Unofficial) 11/15/2018

26. The Commission received NOPR comments from nine entities. We address below the issues raised in the NOPR and comments as well as NERC's revised GMD research work plan and the comments submitted in response. The Appendix to this final rule lists the entities that filed comments in both matters.

II. Discussion

27. Pursuant to section 215(d)(2) of the FPA, the Commission approves Reliability Standard TPL-007-2 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. We conclude that Reliability Standard TPL-007-2 is an improvement over currently-effective Reliability Standard TPL-007-1 and responds to the directives in Order No. 830: (1) to revise the benchmark GMD event definition, as it pertains to the required GMD Vulnerability Assessments and transformer thermal impact assessments, so that the definition is not based solely on spatially-averaged data; (2) to require the collection of necessary GIC monitoring and magnetometer data; and (3) to include a one-year deadline for the completion of corrective action plans and two and four-year deadlines to complete mitigation actions involving non-hardware and hardware mitigation, respectively.[29]

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statistics describing how often extension requests were granted.

[29] In its petition, NERC stated that it would address the directive in Order No. 830 on the collection of GIC monitoring and magnetometer data through a forthcoming NERC data request to applicable entities pursuant to Section 1600 of the NERC Rules of Procedure rather than through a Reliability Standard requirement. NERC Petition at 27. On February 7, 2018, NERC released a draft data request for a 45-day comment period. The NERC Board of Trustees (BOT) subsequently approved the GMD data request at the August 2018 BOT meeting.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

28. Reliability Standard TPL-007-2 complies with the directives in Order No. 830 by requiring, in addition to the benchmark GMD event vulnerability and thermal impact assessments, supplemental GMD vulnerability and thermal impact assessments. The supplemental GMD event definition in Reliability Standard TPL-007-2 contains a non-spatially-averaged reference peak geoelectric field amplitude component of 12 V/km, in contrast to the 8 V/km figure in the spatially-averaged benchmark GMD event definition. As NERC explains in its petition, the supplemental GMD event will be used to "represent conditions associated with localized enhancement of the geomagnetic field during a severe GMD event for use in assessing GMD impacts."[30] Reliability Standard TPL-007-2 therefore addresses the Commission's directive to modify currently-effective Reliability Standard TPL-007-1 so that the benchmark GMD event does not rely solely on spatially-averaged data to calculate the reference peak geoelectric field amplitude.

29. As proposed in the NOPR, pursuant to section 215(d)(5) of the FPA, we also determine that it is appropriate to direct NERC to develop and submit modifications to Reliability Standard TPL-007-2 to require the development and completion of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities. Given that NERC has acknowledged the potential for "severe, localized impacts" associated with supplemental GMD event vulnerabilities, we see no basis for requiring corrective action plans for benchmark GMD events but not for supplemental GMD events.[31] Based on the

[30] NERC Petition at 12.

[31] NERC Petition at 4 ("these revisions would enhance reliability by expanding *(continued ...)*

20181115-3048 FERC PDF (Unofficial) 11/15/2018

record in this proceeding, there appear to be no technical barriers to developing or complying with such a requirement. Moreover, as discussed below, the record supports issuance of a directive at this time, notwithstanding NOPR comments advocating postponement of any directive until after the completion of additional GMD research, because relevant GMD research is scheduled to be completed before the due date for submitting a modified Reliability Standard. The Commission therefore adopts the NOPR proposal and directs NERC to submit the modified Reliability Standard for approval within 12 months from the effective date of Reliability Standard TPL-007-2.

30. We also determine, pursuant to section 215(d)(5) of the FPA, that it is appropriate to direct that NERC develop further modifications to Reliability Standard TPL-007-2, Requirement R7.4. Under NERC's proposal, applicable entities are allowed, without prior approval, to exceed deadlines for completing corrective action plan tasks when "situations beyond the control of the responsible entity [arise]."[32] Instead, as discussed below, we direct NERC to develop a timely and efficient process, consistent with the Commission's guidance in Order No. 830, to consider time extension requests on a case-

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GMD Vulnerability Assessments to include severe, localized impacts and by implementing new deadlines and processes to maintain accountability in the development, completion, and revision of entity Corrective Action Plans developed to address identified vulnerabilities").

[32] In the Supplemental Material section of Reliability Standard TPL-007-2, examples of situations beyond the control of the 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.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

by-case basis. Our directive balances the availability of time extensions when applicable entities are presented with the types of uncontrollable delays identified in NERC's petition and NOPR comments with the need to ensure that the mitigation of known GMD vulnerabilities is not being improperly delayed through such requests. Further, as proposed in the NOPR, we direct NERC to prepare and submit a report addressing how often and why applicable entities are exceeding corrective action plan deadlines as well as the disposition of time extension requests. The report is due within 12 months from the date on which applicable entities must comply with the last requirement of Reliability Standard TPL-007-2. Following receipt of the report, the Commission will determine whether further action is necessary.

31. The Commission, as discussed below, also accepts the revised GMD research work plan submitted by NERC on April 19, 2018.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

A. Corrective Action Plan for Supplemental GMD Event Vulnerabilities NOPR

32. The NOPR proposed to determine that the absence of a requirement to mitigate assessed supplemental GMD event vulnerabilities is inconsistent with Order No. 830, and Order No. 779, because the proposal does not require "owners and operators [to] develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System."[33]

33. The NOPR explained that the Commission was not persuaded by NERC's justification that technical limitations—specifically the small number of observations used to define the supplemental GMD event and the availability of modeling tools to assist entities in assessing vulnerabilities—make requiring mitigation premature at this time.[34] The NOPR, instead, accepted NERC's statement that the supplemental GMD event definition "provides a technically justified method of assessing vulnerabilities to the localized peak effects of severe GMD events."[35] The NOPR also observed that mitigation of supplemental GMD event vulnerabilities is appropriate because Reliability Standard TPL-007-2: (1) does not prescribe how applicable entities must perform such studies, and thus may incorporate any uncertainties regarding the geographic size of such

[33] NOPR, 163 FERC ¶ 61,126 at P 32.

[34] The Commission also rejected the assertion in NERC's petition that an evaluation of possible actions for supplemental GMD events that result in Cascading is similar to the treatment of extreme events in Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements).

[35] NOPR, 163 FERC ¶ 61,126 at P 35 (quoting NERC Petition at 13).

20181115-3048 FERC PDF (Unofficial) 11/15/2018

events into their studies; (2) there are commercially-available tools that could allow for modeling of supplemental GMD events; and (3) other methods could be used within the framework of the Reliability Standard to study planning areas (e.g., superposition or sensitivity studies) in conjunction with other power system modeling tools. The NOPR further recognized that research tasks under way pursuant to the GMD research work plan that are relevant to the supplemental GMD event definition are scheduled to be completed in 2019 and the results of such research should inform the work of the standard drafting team.

Comments

34. NERC does not support the proposed directive. NERC maintains that the provision in Requirement R8.3 that requires applicable entities to evaluate possible actions designed to reduce the likelihood or mitigate the adverse impacts of a supplemental GMD event "is not merely advisory, but rather supports a range of potential mitigating actions, such as additional hardware mitigation, operating procedures, or other resilience actions to enhance recovery and restoration."[36] NERC expounds on this by noting that the requirement to consider mitigation in Reliability Standard TPL-007-2 "would directly support mitigation that is required by [Reliability Standard EOP-010-1]."[37] NERC also contends that it "anticipates that the Corrective Action Plans, when needed to address performance requirements for the benchmark GMD event, will also

[36] NERC Comments at 9.

[37] *Id.* at 10.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

provide a large degree of protection to the Bulk-Power System for events with locally-enhanced geomagnetic fields."[38]

35. NERC's comments reiterate the rationale in its petition that requiring mitigation "would result in the de facto replacement of the benchmark GMD event with the proposed supplemental GMD event."[39] NERC maintains that "while the supplemental GMD event is strongly supported by data and analysis in ways that mirror the benchmark GMD event, there are aspects of it that are less definitive than the benchmark GMD event and less appropriate as the basis of requiring Corrective Action Plans."[40] NERC also claims that the uncertainty of geographic size of the supplemental GMD event could not be addressed adequately by sensitivity analysis or through other methods because there are "inherent sources of modeling uncertainty (e.g., earth conductivity model, substation grounding grid resistance values, transformer thermal and magnetic response models) … [and] introducing additional variables for sensitivity analysis, such as the size of the localized enhancement, may not improve the accuracy of GMD Vulnerability Assessments."[41] NERC further states that "commercially-available modeling tools now advertise capabilities that could be used to model localized GMD enhancements, [but] to

[38] *Id.* at 11.

[39] *Id.* at 11-12; *see also id.* at 14 ("many entities would likely employ the most conservative approach for conducting supplemental GMD Vulnerability Assessments, which would be to apply extreme peak values uniformly over an entire planning area").

[40] *Id.* at 13.

[41] *Id.* at 15.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

NERC's knowledge these capabilities have not been used extensively by planners, nor have the different software tools been benchmarked for consistency in results."[42]

36. NERC contends that completing the GMD work plan is a better alternative to the NOPR directive. Moreover, NERC states that it "commits to initiate a review of TPL-007-2 following the completion of the GMD Research Work Plan to evaluate whether the standard continues to be supported by the available knowledge or whether additional refinements are necessary … [which] could result in modifications to, or additional support for, the proposed supplemental GMD event, and thereby inform what the TPL-007 standard should require in terms of mitigation based on supplemental GMD Vulnerability Assessments."[43] In response to the NOPR's statement that the results of the GMD research work plan may inform the work of the standard drafting team tasked with carrying out the Commission's proposed directive, NERC comments state that "it expects that the last of the project's deliverables will be ready by early 2020 … [but] [a]ny scientific research project schedule, however, must account for the possibility that additional time may be needed to explore potential findings or amend project approaches to provide more useful results."[44] NERC states that while the technical report for Task 1 is scheduled to be completed by the fourth quarter of 2019 according to the revised GMD

[42] *Id.*

[43] *Id.* at 18.

[44] *Id.* at 17.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

research work plan, NERC estimates that it will file a report with the Commission, after allowing a period of public comment, six months later (i.e., mid-2020).[45]

37. Trade Associations, Idaho Power, NE ISO, TVA and BPA do not support the proposed directive. They contend that requiring corrective action plans for supplemental GMD event vulnerabilities: (1) may be premature given the limited data regarding localized GMD events; (2) would address low-probability events that are unlikely to affect a wide area; and (3) could impose costs on applicable entities that outweigh the potential benefits of such a directive. Like NERC, these commenters support completing the GMD research work plan before considering mandating corrective action plans for supplemental GMD event vulnerabilities. Idaho Power, moreover, contends that it would be better for registered entities to gain experience with corrective action plans for benchmark GMD events before mandating corrective action plans for supplemental GMD events. Trade Associations state that instead of the NOPR directive, any Commission directive should be limited to requiring NERC to develop "a study of the mitigation measures deployed and the effectiveness of these measures to mitigate benchmark GMD events before mandating mitigation measures on more localized events."[46] Similarly,

[45] Revised GMD Research Work Plan at 5 ("NERC expects to submit [informational filings with the Commission] approximately six months following EPRI's completion of the associated technical report(s)"); *id.*, Attachment 1 (Order No. 830 GMD Research Work Plan (April 2018)) at 7 (identifying "Q4 2019" as the estimated completion date of "Final technical report to provide additional technical support for the existing supplementary (localized) benchmark; or, propose update to the benchmark, as appropriate").

[46] Trade Associations Comments at 12.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

BPA maintains that instead of the NOPR directive, in order to assess the costs and benefits of requiring corrective action plans for supplemental GMD events, the Commission should require NERC to file periodic reports on supplemental GMD events and the possible actions to mitigate them.

38. Resilient Societies and Reclamation support the NOPR directive. Reclamation states, and Resilient Societies concurs, that "[a]n exercise to only identify vulnerabilities arising from localized GMD events is not a cost-effective use of resources unless accompanied by activities to mitigate the identified vulnerabilities."[47]

Commission Determination

39. Pursuant to section 215(d)(5) of the FPA, the Commission adopts the NOPR proposal and directs NERC to develop and submit modifications to Reliability Standard TPL-007-2 to require corrective action plans for assessed supplemental GMD event vulnerabilities. While Reliability Standard TPL-007-2 requires applicable entities to assess supplemental GMD event vulnerabilities, it does not require corrective action plans to address assessed vulnerabilities. Instead, Reliability Standard TPL-007-2, Requirement R8.3 only requires applicable entities to make "an evaluation of possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the events if a supplemental GMD event is assessed to result in Cascading." As the Commission observed in the NOPR, NERC's proposal differs significantly from Order

[47] Reclamation Comments at 1; Resilient Societies Comments at 3.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

No. 830 because the intent of the directive was not only to identify vulnerabilities arising from localized GMD events but also to mitigate such vulnerabilities.

40. The comments opposing the NOPR directive offer two rationales for approving Reliability Standard TPL-007-2 without directing modifications at this time: (1) Reliability Standard TPL-007-2 provides sufficient protection against supplemental GMD event vulnerabilities; and (2) requiring mitigation of supplemental GMD events is premature at this time.

41. With respect to the first rationale, NERC observes that the provision requiring applicable entities to consider supplemental GMD event mitigation is not "merely advisory." However, there is no dispute that an applicable entity must "consider" mitigation under Reliability Standard TPL-007-2. What is significant is that after having done so, an applicable entity has no obligation under Reliability Standard TPL-007-2 to implement mitigation even if the applicable entity "considered" mitigation necessary to address an assessed supplemental GMD event vulnerability.

42. NERC also maintains that Reliability Standard EOP-010-1 requires transmission operators to "develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system." And in Order No. 779, the Commission determined that "while the development of the required mitigation plan [for benchmark GMD event vulnerabilities] cannot be limited to considering operational procedures or enhanced training alone, operational procedures and enhanced training may be sufficient if that is verified by the

20181115-3048 FERC PDF (Unofficial) 11/15/2018

vulnerability assessments."[48] Again, NERC's point does not resolve the Commission's concern because Reliability Standard EOP-010-1 does not ensure mitigation of all supplemental GMD event vulnerabilities assessed under Reliability Standard TPL-007-2. That is because: (1) Reliability Standard EOP-010-1 applies, in relevant part, only to transmission operators (viz., it does not apply to other applicable entity types, such as planning coordinators, transmission planners and generator owners, subject to Reliability Standard TPL-007-2); and (2) Reliability Standard EOP-010-1 does not require mitigation if the supplemental GMD event vulnerability cannot be addressed through operational procedures or enhanced training alone. Thus, Reliability Standard EOP-010-1 does not ensure satisfactory mitigation or provide an adequate substitute for mitigation as contemplated in Order No. 830.

43. In addition, NERC asserts that the required mitigation of benchmark GMD event vulnerabilities could also address supplemental GMD event vulnerabilities. Of course that may occur in some circumstances, but that is not a substitute for requiring mitigation to the extent that benchmark GMD event mitigation does not completely address a supplemental GMD event vulnerability. Under Reliability Standard TPL-007-2 there is currently no requirement to mitigate the remaining vulnerability to the Bulk-Power System.

44. Regarding the second rationale in the NOPR comments, NERC and other commenters reiterate the assertion in NERC's petition that it would be premature, from a

[48] Order No. 779, 143 FERC ¶ 61,147 at P 83.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

technical standpoint, to require corrective action plans to address supplemental GMD event vulnerabilities. As reflected in the comment summary, these commenters instead request that NERC complete the GMD research work plan and then produce a report that assesses the possible need for modifications to Reliability Standard TPL-007-2.

45. The NOPR discussed how a standard drafting team could use new information gathered through the GMD research work plan to develop a modified Reliability Standard. The Commission noted that Task 1 of the GMD research work plan (Further Analyze Spatial Averaging Used in the Benchmark GMD Event), which encompasses localized GMD event research, would be delivered in 2019 according to the most recent version of the GMD research work plan (i.e., the revised GMD research work plan). The NOPR stated that "[s]uch GMD research on localized events should inform the standard development process and aid applicable entities when implementing a modified Reliability Standard."[49] While we appreciate that the informational filing for Task 1 may not be submitted to the Commission prior to the deadline for submitting a modified Reliability Standard, the underlying research in Task 1 is scheduled to be completed before then. As such, the standard drafting team and personnel working on the GMD research work plan could operate in parallel and share information to ensure that research relevant to the Commission's directive is incorporated into the modified Reliability Standard. Thus we are not persuaded by the comments seeking a delay of our directive.

[49] NOPR, 163 FERC ¶ 61,126 at P 39.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

46. We are not persuaded by the other points raised by commenters to support their assertion that requiring corrective action plans is premature. First, NERC assumes that under such a requirement "many" applicable entities will adopt a "conservative approach" and use the supplemental GMD event definition in all GMD vulnerability assessments, thus effectively supplanting the benchmark GMD event definition. NERC bases this assumption on the standard drafting team's "extensive experience in system planning and the relative immaturity of tools and methods for modeling localized enhancements."[50] NERC acknowledges the discussion in the NOPR on how uncertainties regarding the supplemental GMD event definition—in particular the geographic size of localized events—are ameliorated by the flexibility afforded by Reliability Standard TPL-007-2. Specifically, Reliability Standard TPL-007-2 permits applicable entities to apply the supplemental GMD event definition to an entire planning area or any subset of a planning area. However, NERC asserts that even with this flexibility, at least some applicable entities would default to using the supplemental GMD event definition in an overly-broad manner. Notwithstanding NERC's assertion, nothing in Reliability Standard TPL-007-2 requires applicable entities to apply the supplemental GMD event definition to an entire planning area or otherwise supplant the benchmark GMD event definition.

47. With respect to the statement in the NOPR that modeling tools are currently available to support corrective action plans, NERC admits that "some commercially-

[50] NERC Comments at 14.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

available modeling tools now advertise capabilities that could be used to model localized GMD enhancements."[51] However, NERC contends that to its "knowledge these capabilities have not been used extensively by planners, nor have the different software tools been benchmarked for consistency in result."[52] Given that GMDs have only recently been addressed in the Reliability Standards and there is currently no requirement to model and assess, let alone mitigate, localized GMD events, it is not unexpected that these modeling tools have not been used extensively for that purpose. Moreover, NERC does not assert that existing tools are incapable of performing the desired modeling function.[53] Thus, NERC's objections on this point are not persuasive.

48. NERC does not offer support for its comment in response to the NOPR's observation that sensitivity analysis can serve, among other methods, as a method to refine the geographic scope of localized GMD impacts on planning areas. NERC responds that it "does not believe that concerns regarding the uncertainty of the geographic size of the supplemental GMD event could be addressed adequately by sensitivity analysis or though other methods in planning studies."[54] NERC claims there are already inherent sources of modeling uncertainty and that introducing another

[51] *Id.* at 15.

[52] *Id.* at 15-16.

[53] *See also* Trade Associations Comments at 8 ("Although current tools are available to model localized events, we understand that such modeling will require significant time as the processes involved are still largely manual, making it difficult to develop accurate, system-wide models that appropriately consider the localized impacts of the supplemental GMD event.").

[54] NERC Comments at 15.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

variable, such as the size of the localized enhancement, "may not improve the accuracy of the GMD Vulnerability Analysis."[55] And yet NERC's concern implies that the benchmark GMD event contains a geographic domain that does not itself inject uncertainties. However, as the Commission stated in Order No. 830, the geographic area for spatial averaging in the benchmark GMD event definition is itself a "subjective" figure.[56] Indeed, in Order No. 830, as part of the GMD research work plan directive, to address the uncertainties surrounding the geographic scale of spatial averaging, the Commission directed that NERC should "further analyze the area over which spatial averaging should be calculated for stability studies, including performing sensitivity analyses on squares less than 500 km per side (e.g., 100 km, 200 km)," which NERC is addressing in Task 1.[57] As such, we see no basis, technical or otherwise, for not requiring corrective action plans for assessed supplemental GMD event vulnerabilities while requiring corrective action plans for assessed benchmark GMD event vulnerabilities consistent with the Commission's directions in Order Nos. 779 and 830. Accordingly, the Commission is not persuaded by the arguments of NERC and other commenters for

[55] *Id.*

[56] Order No. 830, 156 FERC ¶ 61,215 at P 45 (quoting Pulkkinen, A., Bernabeu, E., Eichner, J., Viljanen, A., Ngwira, C., "Regional-Scale High-Latitude Extreme Geoelectric Fields Pertaining to Geomagnetically Induced Currents," Earth, Planets and Space at 2 (June 19, 2015)).

[57] *Id.* P 26; *see also* revised GMD Research Work Plan (Task 1) at 6 ("further analyze the area over which spatial averaging should be used in stability studies and transformer thermal assessments by performing GIC analysis on squares less than 500 km per side (e.g., 100 km, 200 km) and using the results to perform power flow and transformer thermal assessments").

20181115-3048 FERC PDF (Unofficial) 11/15/2018

the reasons discussed above, and directs that NERC develop modifications to Reliability Standard TPL-007-2 to require corrective action plans for assessed supplemental GMD event vulnerabilities.

B. Corrective Action Plan Deadline Extensions

NOPR

49. The NOPR stated that Requirement R7.4 of Reliability Standard TPL-007-2 differs from Order No. 830 by allowing applicable entities to "revise" or "update" corrective action plans to extend deadlines. This provision contrasts with the guidance in Order No. 830 that "NERC should consider extensions of time on a case-by-case basis." While agreeing that there should be a mechanism for allowing extensions of corrective action plan implementation deadlines, the NOPR expressed concern with unnecessary delays in implementing protection against GMD threats.

50. The NOPR identified two options for addressing Requirement R7.4. Under the first option, the Commission would, pursuant to section 215(d)(5) of the FPA, direct NERC to modify Reliability Standard TPL-007-2 to comport with Order No. 830, 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. The Commission would also direct NERC to prepare and submit a report addressing the disposition of any such requests, as well as information regarding how often and why applicable entities are exceeding corrective action plan deadlines following implementation of Reliability

20181115-3048 FERC PDF (Unofficial) 11/15/2018

Standard TPL-007-2. Under such a directive, NERC would submit the report within 12 months from the date on which applicable entities must comply with the last requirement of Reliability Standard TPL-007-2. Following receipt of the report, the Commission would determine whether further action is necessary. Under the second option, the Commission would approve proposed Requirement R7.4 but also direct NERC to prepare and submit the report described in the first option (without the statistics on disposition). Following receipt of the report, the Commission would determine whether further action is necessary.

Comments

51. NERC supports the second option in the NOPR. NERC contends that Reliability Standard TPL-007-2 "provides clarity and certainty regarding when an entity may extend a Corrective Action Plan mitigation deadline and what steps must be followed to maintain accountability and thus compliance with the standard."[58] NERC also maintains that the proposal "avoids the administrative burden, uncertainty, and further delay that could be associated with implementing a new ERO adjudication process, such as one that would be dedicated to evaluating GMD Corrective Action Plan deadline extensions on a case-by-case basis."[59] To address concerns regarding the possible abuse of deadline extensions, NERC states that as "part of the compliance monitoring and enforcement activities for the proposed standard, NERC and Regional Entity staff would exercise their

[58] NERC Comments at 20.

[59] *Id.*

20181115-3048 FERC PDF (Unofficial) 11/15/2018

authority to review the reasonableness of any Corrective Action Plan delay, including reviewing the 'situations beyond the control of the responsible entity' that are cited as causing the delay."[60] As noted in the Supplemental Material section of Reliability Standard TPL-007-2, NERC explains that examples of such situations include "lengthy legal or regulatory processes, stakeholder processes required by tariff, or long equipment lead times."[61] NERC, moreover, "agrees that a report describing the results of NERC's monitoring of this provision could provide useful information … [and] therefore commits to prepare and submit to the Commission a report that describes how often and the reasons why entities in the United States are exceeding Corrective Action Plan deadlines."[62]

52. Trade Associations, BPA, ISO NE, Idaho Power, and TVA support the second option and echo the rationale for adopting the second option in NERC's comments. Trade Associations explain that while they previously supported a case-by-case exception process, they now believe NERC's proposal to be more efficient and effective. Trade Associations contend that a case-by-case approach would "only increase administrative tasks for NERC and applicable entities … [and] would further delay any actions to mitigate rather than expedite the approval process."[63] Trade Associations also maintain

[60] *Id.* at 20-21.

[61] *Id.* at 20.

[62] *Id.* at 22.

[63] Trade Associations Comments at 13.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

that Reliability Standard TPL-007-2 "will not delay mitigation because this requirement is only applicable if circumstances are beyond the entity's control."[64]

53. Reclamation does not appear to support modifying Requirement R7 to institute a case-by-case time extension process. However, Reclamation comments that the sub-requirement in Requirement R7.4.1 requiring documentation of reasons for delaying corrective action plans should be eliminated because it "is merely a compliance exercise and does not improve Bulk Electric System reliability." Reclamation makes the same contention regarding the sub-requirement in Requirement R7.4.2 that a revised corrective action plan describe the original corrective action plan.

Commission Determination

54. Reliability Standard TPL-007-2, Requirement R7.4 differs from Order No. 830 by allowing applicable entities, under certain conditions, to extend corrective action plan implementation deadlines without prior approval. This conflicts with the Commission's guidance in Order No. 830 that, using its compliance discretion, "NERC should consider extensions of time on a case-by-case basis."[65] Based on our consideration of the record, we believe that the case-by-case review process contemplated by Order No. 830 is the appropriate means for considering extension requests. Accordingly, pursuant to section 215(d)(5) of the FPA, we direct that NERC develop modifications to Reliability Standard

[64] *Id.*

[65] Order No. 830, 156 FERC ¶ 61,215 at P 102.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

TPL-007-2 to replace the time-extension provision in Requirement R7.4 with a process through which extensions of time are considered on a case-by-case basis.

55. At the outset, we note that the extension process in Requirement R7.4 applies only to the implementation of corrective action plans and not to the development of corrective action plans.[66] NERC and other commenters supportive of the second option in the NOPR urge approval of Requirement R7.4 without modification largely because of the perceived uncertainty and burden associated with treating extension requests on a case-by-case basis. While it is true that granting extensions on a case-by-case basis involves more uncertainty and potential burdens versus the automatic extension of time afforded by Requirement R7.4, we must weigh this against the potential for abuse of Requirement R7.4 to unduly delay mitigation, as well as the delayed visibility that NERC would have into the deployment of needed GMD protections. Presented with these competing concerns, we conclude that the imperative to address known GMD vulnerabilities in a timely manner, and without unwarranted delays, is more compelling. We recognize that applicable entities that have a legitimate need for extensions require timely responses from NERC and Regional Entities, as appropriate. Accordingly, we expect that the extension process developed by NERC in response to our directive will be timely and efficient such that applicable entities will receive prompt responses after submitting to

[66] Reliability Standard TPL-007-2, Requirement R7.4 ("[t]he [corrective action plan] shall … [b]e revised if situations beyond the control of the responsible entity … prevent implementation of the [corrective action plan] within the timetable for implementation").

20181115-3048 FERC PDF (Unofficial) 11/15/2018

NERC or a Regional Entity, as appropriate, the extension request and associated information described in Requirement R7.4.[67]

56. In reaching our determination on this issue, we considered NERC's NOPR comments, which attempted to address the concerns with Requirement R7.4 expressed in the NOPR, stating that NERC and Regional Entity compliance and enforcement staff will review the reasonableness of any delay in implementing corrective action plans, including reviewing the asserted "situations beyond the control of the responsible entity" cited by the applicable entity, and by citing specific examples of the types of delays that might justify the invocation of Requirement R7.4. NERC's comments also characterized Requirement R7.4 as being "not so flexible … as to allow entities to extend Corrective Action Plan deadlines indefinitely or for any reason whatsoever."[68] We generally agree with the standard of review that NERC indicates it will use to determine whether an extension of time to implement a corrective action plan is appropriate. However, the assessment of whether an extension of time is warranted is more appropriately made before an applicable entity is permitted to delay mitigation of a known GMD vulnerability. While NERC indicates that under proposed Requirement R7.4 there are compliance consequences for improperly delaying mitigation, mitigation of a known GMD vulnerability will nonetheless have been delayed, and we conclude it is important that any proposed delay be reviewed ahead of time. Therefore, we direct NERC to

[67] NOPR, 163 FERC ¶ 61,126 at P 50.

[68] NERC Comments at 20.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

modify Reliability Standard TPL-007-2, Requirement R7.4 to develop a timely and efficient process, consistent with the Commission's guidance in Order No. 830, to consider time extension requests on a case-by-case basis.

57. We disagree with Reclamation's comment regarding Requirement R7.4.1, which requires a description of the circumstances necessitating mitigation delays, because it is at odds with NERC's NOPR comments, discussed above, in which NERC states that NERC and Regional Entities will review the reasons for delaying mitigation. Contrary to Reclamation's assertion that this requirement is "merely a documentation exercise and does not improve [bulk electric system] reliability," unreasonable delays of mitigation could harm bulk electric system reliability by leaving it vulnerable to GMDs. Moreover, Requirement R7.4.2, also opposed by Reclamation, requiring that revised corrective action plans describe the original and previous revisions, provides compliance enforcement authorities with a revision history of the corrective action plan in a single document, thus facilitating compliance review.

C. Other Issues Raised in NOPR Comments

58. Resilient Societies' comments raise three issues not addressed in the NOPR. First, Resilient Societies maintains that transformers that experience an estimated GIC above 15 A/phase should be subject to mandatory corrective action plans and the Commission should "encourage owner-operators and their research partners to develop 'Corrective Action Plans' for both [extra high voltage] transformers and for associated generation stations, even if these long replacement-time systems experience overstress at levels significantly below 75 amps per phase." Second, Resilient Societies states that the

20181115-3048 FERC PDF (Unofficial) 11/15/2018

Commission should encourage best practices by industry beyond the mandatory requirements of the Reliability Standards, including allowing cost recovery for such practices. Third, Resilient Societies states that the Commission should address combined GMD and electromagnetic pulse (EMP) protection.

59. In Order No. 830, the Commission approved the 75 A/phase threshold in Reliability Standard TPL-007-1 based on the record and despite objections from certain commenters. The Commission, however, directed further study of this issue as part of the GMD research work plan. Resilient Societies' comments provide no new basis for revisiting this issue at this time. Moreover, as reflected in the NOPR proposal, NERC has adequately supported the 85 A/phase threshold proposed in Reliability Standard TPL-007-2 for the supplemental GMD event analysis. However, new information resulting from the GMD research work plan will also be relevant to this higher threshold. We will consider such research at the appropriate time.

60. In Order No. 830, the Commission stated that "cost recovery for prudent costs associated with or incurred to comply with Reliability Standard TPL-007-1 and future revisions to the Reliability Standard will be available to registered entities."[69] It is therefore beyond the scope of this proceeding to determine, as a general matter, whether voluntary measures beyond those required to comply with the governing Reliability Standards are eligible for cost recovery. That said, jurisdictional entities may of course

[69] Order No. 830, 156 FERC ¶ 61,215 at P 24.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

pursue such voluntary measures, and the Commission would consider appropriate cost recovery for those investments through a formula rate or other rate proceeding.

61. The Commission in previous orders has indicated that the Commission's GMD proceedings are not directed to EMPs and thus Resilient Societies' comments on EMP are out-of-scope.[70]

D. Revised GMD Research Work Plan

62. On April 19, 2018, NERC submitted a revised GMD research work plan in response to a Commission order issued on October 19, 2017.[71] In the October 19 Order, the Commission accepted the initial GMD research work plan filed by NERC on May 30, 2017. The Commission also directed NERC to file a final GMD research work plan within six months and ensure that the final GMD research work plan included a reevaluation of reliance on single station readings when adjusting for latitude as part of the benchmark GMD event definition. At NERC's request, the October 19 Order also provided guidance on how NERC should prioritize the tasks in the GMD research work plan.

63. Bardin and Resilient Societies submitted comments in response to the revised GMD research work plan, which largely focused on a request for combined research on GMDs and EMPs. As discussed above, however, EMPs are outside the scope of the Commission's directive regarding GMD research. Resilient Societies also submitted

[70] *See, e.g.*, Order No. 830, 156 FERC ¶ 61,215 at P 119.

[71] *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, 161 FERC ¶ 61,048 (2017) (October 19 Order).

20181115-3048 FERC PDF (Unofficial) 11/15/2018

comments criticizing aspects of five tasks in the revised GMD research work plan. With respect to Tasks 1, 2, 8 and 9, Resilient Societies' criticism is based on the contention that the "real-world data" will not be used to verify models. For example, Resilient Societies contends that NERC will not use "real-world" GIC data to validate spatial averaging (Task 1) or latitude scaling (Task 2). These assertions, however, are refuted by the revised GMD research work plan. The revised GMD research work plan indicates that the research on spatial averaging includes an analysis of "a large number (10-20) of localized extreme events and collection of both ground-based and space-based data around the times of these events."[72] For latitude scaling, the revised GMD research work plan states that NERC will evaluate the scaling factor "using existing models and developing new models to extrapolate, from historical data, the potential scaling of a 1-in-100 year GMD event on lower geomagnetic latitudes."[73] In addition, NERC indicates that the data gathered through the Section 1600 data request "will help validate various models used in calculating GIC's and assessing their impacts in data systems."[74]

64. Resilient Societies other comments are directed to an alleged lack of specificity, granularity or "scientific assurance" in the testing described in Tasks 5, 8 and 9 of the revised GMD research work plan. These criticisms are misplaced as they demand an

[72] Revised GMD Research Work Plan, Attachment 1 (Order No. 830 GMD Research Work Plan (April 2018)) at 2.

[73] *Id.* at 8.

[74] *Id.* at 19.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

unreasonable degree of detail in the revised GMD research work plan. For example, regarding Task 5, NERC states that it will "validate[e] existing transformer tools with all data that is presently available and with upcoming field/laboratory test results."[75] Resilient Societies, however, contends unpersuasively that "NERC neglects to specify 'all data that is presently available' … and the number of transformers to be employed in 'upcoming field laboratory test results' and also neglects to disclose details of the test protocols to be used."[76] Regarding harmonics (Tasks 8 and 9), Task 9 specifically includes "tank vibration measurements," not just simulations.[77] Moreover, Task 8 (Improving Harmonic Analysis Capabilities) is intended to develop more basic information than some of the other tasks in the revised GMD research work plan where industry has more knowledge. As with all of the revised GMD research work plan tasks (with the exception of Task 6, which deals with the Section 1600 data request), NERC will submit a report to the Commission on its findings.

65. As the revised GMD research work plan complies with Order No. 830 and the Commission's October 19 Order, we accept the revised GMD research work plan.

III. Information Collection Statement

66. The collection of information contained in this final rule is subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork

[75] *Id.* at 17.

[76] Resilient Societies Comments on Revised GMD Research Work Plan at 11.

[77] *Id.* at 25.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

Reduction Act of 1995.[78] OMB's regulations require review and approval of certain information collection requirements imposed by agency rules.[79] Upon approval of a collection of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the information collection requirements of a rule will not be penalized for failing to respond to the collection of information unless the collection of information displays a valid OMB control number.

67. In the NOPR, the Commission solicited comments on the need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. Specifically, the Commission asked that any revised burden or cost estimates submitted by commenters be supported by sufficient detail to understand how the estimates were generated. The Commission did not receive any comments regarding the Commission's burden estimates.

68. The Commission approves Reliability Standard TPL-007-2, which replaces currently-effective Reliability Standard TPL-007-1. When compared to Reliability Standard TPL-007-1, Reliability Standard TPL-007-2 maintains the current information collection requirements, modifies existing Requirements R1 through R7 and adds new requirements in Requirements R8 through R12.

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[78] 44 U.S.C. 3507(d).

[79] 5 CFR 1320 (2018).

20181115-3048 FERC PDF (Unofficial) 11/15/2018

69. Reliability Standard TPL-007-2 includes new corrective action plan development and implementation deadlines in Requirement R7, new supplemental GMD vulnerability and transformer thermal impact assessments in Requirements R8 through R10, and requirements for applicable entities to gather magnetometer and GIC monitored data in Requirements R11 and R12. Deadlines in Requirement R7 for the development and implementation of corrective action plans would only change the timeline of such documentation and are not expected to revise the burden to applicable entities. The burden estimates for new Requirements R8 through R10 are expected to be similar to the burden estimates for Requirements R4 through R6 in currently-effective Reliability Standard TPL-007-1 due to the closely-mirrored requirements.[80] The Commission expects that only 25 percent or fewer of transmission owners and generator owners would have to complete a supplemental transformer thermal impact assessment per Requirement R10. Requirements R11 and R12 require applicable entities to have a process to collect GIC and magnetometer data from meters in planning coordinator planning areas.

Public Reporting Burden: The burden and cost estimates below are based on the changes to the reporting and recordkeeping burden imposed by Reliability Standard TPL-007-2. Our estimates for the number of respondents are based on the NERC Compliance Registry as of March 3, 2018, which indicates there are 183 entities registered as transmission planner (TP), 65 planning coordinators (PC), 330 transmission owners (TO), 944 generator owners (GO) within the United States. However, due to significant

[80] NERC Petition at 14-17.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

overlap, the total number of unique affected entities (i.e., entities registered as a transmission planner, planning coordinator, transmission owner or generator owner, or some combination of these functional entities) is 1,130 entities. This includes 188 entities that are registered as a transmission planner or planning coordinator (applicability for Requirements R7 to R9 and R11 to R12), and 1,119 entities registered as a transmission or generation owner (applicability for Requirement R10). Given the assumption above, there is an expectation that at most only 25 percent of the 1,119 entities (or 280 entities) will have to complete compliance activities for Requirement R10. The estimated burden and cost are as follow.[81]

FERC-725N, Changes Due to Final Rule in Docket No. RM18-8[82, 83]

[81] Hourly costs are based on the Bureau of Labor Statistics (BLS) figures for May 2017 (Sector 22, Utilities) for wages (https://www.bls.gov/oes/current/naics2_22.htm) and benefits for December 2017 (https://www.bls.gov/news.release/ecec.nr0.htm). We estimate that an Electrical Engineer (NAICS code 17-2071) would perform the functions associated with reporting requirements, at an average hourly cost (for wages and benefits) of $66.90 The functions associated with recordkeeping requirements, we estimate, would be performed by a File Clerk (NAICS code 43-4071) at an average hourly cost of $32.04 for wages and benefits.

The estimated burden and cost are in addition to the burden and cost that are associated with the existing requirements in Reliability Standard TPL-007-1 (and in the current OMB-approved inventory), which would continue under Reliability Standard TPL-007-2.

The requirements for NERC to provide reports to the Commission and to develop and submit modifications to Reliability Standard TPL-007-2 are already covered under FERC-725 (OMB Control No. 1902-0225).

[82] Rep.=reporting requirements; RK =recordkeeping requirements (Evidence Retention).

20181115-3048 FERC PDF (Unofficial) 11/15/2018

Requirement (R)	Number and Type of Respondents (1)	Annual Number of Responses Per Respondent (2)	Total No. of Responses (1)X(2)=(3)	Average Burden Hrs. & Cost per Response (4)	Total Annual Burden Hrs. & Total Annual Cost (rounded) (3)X(4)=(5)	Cost per Respondent ($) (5)÷(1)
R1 through R6[84]	No change	No change	No change	No change	No change	No change
R7	188 (PC and TP)	1/5 (once for every five year study)	37.6	Rep. 5 hrs., $334.50; RK 5 hrs., $160.20	Rep. 188 hrs., $12,577; RK 188 hrs., $6,023	Rep. 1 hr., $66.90; RK 1 hr., $32.04
R8	188 (PC and TP)	1/5 (once for every five year study)	37.6	Rep., 27 hrs., $1,806.30; RK, 21 hrs., $672.84	Rep. 1,015 hrs., $67,917; RK 790 hrs., $25,299	Rep., 5.4 hrs., $361.26; RK 4.2 hrs., $134.57
R9	188 (PC and TP)	1/5 (once for every five year study)	37.6	Rep. 9 hrs., $602.10; RK 7 hrs., $224.28	Rep. 338 hrs., $22,639; RK 263 hrs., $8,432	Rep. 1.8 hrs., $120.42; RK 1.4 hrs., $44.85

[83] For each Reliability Standard, the Measure shows the acceptable evidence (Reporting Requirement) for the associated Requirement (R numbers), and the Compliance section details the related Recordkeeping Requirement.

[84] While Reliability Standard TPL-007-2 extends the requirements in existing Reliability Standard TPL-007-1, Requirements R1 through R3 to the newly required supplemental GMD event analyses, the obligation to conduct the supplemental GMD event analyses is found in Reliability Standard TPL-007-2, Requirements R8 through R10.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

R10	280 (25% of 1,119) (GO and TO)	1/5 (once for every five year study)	56	Rep. 22 hrs., $1,471.80; RK 18 hrs., $576.72	Rep. 1,232 hrs., $82,421; RK 1,008 hrs., $32,296	Rep. 4.4 hrs., $294.36; RK 3.6 hrs., $115.34
R11	188 (PC and TP)	1 (on-going reporting)	188	Rep. 10 hrs., $669; RK. 10 hrs., $320.40	Rep. 1,880 hrs., $125,772; RK 1,880 hrs., $60,235	Rep. 10 hrs., $669; RK 10 hrs., $320.40
R12	188 (PC and TP)	1 (on-going reporting)	188	Rep. 10 hrs., $669; RK. 10 hrs., 320.40	Rep. 1,880 hrs. $125,772; RK 1,880 hrs., $60,235	Rep. 10 hrs., $669; RK 10 hrs., $320.40
Total Additional Hrs. and Cost (rounded), due to Final Rule in RM18-8					Rep., 6,533 hrs., $437,057; RK 6,009 hrs., $192,528	

Title: FERC-725N, Mandatory Reliability Standards: TPL Reliability Standards

Action: Revisions to an existing collection of information

OMB Control No: 1902-0264

Respondents: Business or other for profit, and not for profit institutions.

Frequency of Responses:[85] Every five years (for Requirement R7-R10), annually (for Requirement R11 and R12), and ongoing.

[85] The frequency of Requirements R1 through R6 in Reliability Standard TPL- *(continued ...)*

20181115-3048 FERC PDF (Unofficial) 11/15/2018

Necessity of the Information: Reliability Standard TPL-007-2 implements the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk-Power System. Specifically, these requirements address the threat posed by GMD events to the Bulk-Power System and conform to the Commission's directives to modify Reliability Standard TPL-007-1 as directed in Order No. 830.

Internal review: The Commission has reviewed Reliability Standard TPL-007-2, and made a determination that its action is necessary to implement section 215 of the FPA. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

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

71. Comments concerning the collection of information and the associated burden estimate should be sent to the Commission in this docket and may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. Due to security concerns, comments should be sent electronically to the following e-mail address: oira_submission@omb.eop.gov.

007-2 is unchanged from the existing requirements in Reliability Standard TPL-007-1.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

Comments submitted to OMB should refer to FERC-725N and OMB Control No. 1902-0264.

IV. Environmental Analysis

72. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[86] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[87] The actions here fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act

73. The Regulatory Flexibility Act of 1980 (RFA)[88] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. The definition of small business is provided by the Small Business Administration (SBA) at 13 CFR 121.201. The threshold for a small utility (using SBA's sub-sector 221) is based on the number of employees for a concern and its affiliates. As discussed above, Reliability Standard TPL-007-2 applies to a total of 1,130

[86] Regulations Implementing the National Environmental Policy Act *of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

[87] 18 CFR 380.4(a)(2)(ii) (2018).

[88] 5 U.S.C. 601-12.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

unique planning coordinators, transmission planners, transmission owners, and generation owners.[89] A small utility (and its affiliates) is defined as having no more than

[89] In the NERC Registry, there are approximately 65 PCs, 188 TPs, 944 GOs, and 330 TOs (in the United States), which will be affected by this final rule. Because some entities serve in more than one role, these figures involve some double counting.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

the following number of employees:

- for planning coordinators, transmission planners, and transmission owners (NAICS code 221121, Electric Bulk Power Transmission and Control), a maximum of 500 employees
- for generator owners, a maximum of 750 employees.[90]

74. As estimated in the NOPR, the total cost to all entities (large and small) is $629,585 annually (or an average of $1,345.27 for each of the estimated 468 entities affected annually). For the estimated 280 generator owners and transmission owners affected annually, the average cost would be $409.70 per year. For the estimated 188 planning coordinators and transmission planners, the estimated average annual cost would be $2,738.84. The estimated annual cost to each affected entity varies from $409.70 to $2,738.84 and is not considered significant. The Commission did not receive any comments regarding these burden and cost estimates.

75. Accordingly, the Commission certifies that this final rule will not have a significant economic impact on a substantial number of small entities.

VI. Document Availability

76. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the

[90] The maximum number of employees for a generator owner (and its affiliates) to be "small" varies from 250 to 750 employees, depending on the type of generation (e.g., hydroelectric, nuclear, fossil fuel, wind). For this analysis, we use the most conservative threshold of 750 employees.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

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

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

VII. Effective Date and Congressional Notification

79. These regulations are effective **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory

20181115-3048 FERC PDF (Unofficial) 11/15/2018

Enforcement Fairness Act of 1996. The rule will be provided to the Senate, House, Government Accountability Office, and the SBA.

By the Commission. Commissioner McIntyre is not voting on this order.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

20181115-3048 FERC PDF (Unofficial) 11/15/2018

APPENDIX

List of Commenters

Abbreviation	Commenter
Bardin	David Bardin
BPA	Bonneville Power Administration
Idaho Power	Idaho Power Company
ISO NE	ISO New England Inc.
NERC	North American Electric Reliability Corporation
Reclamation	Bureau of Reclamation
Resilient Societies	Foundation for Resilient Societies
Trade Associations	American Public Power Association, Edison Electric Institute, Electricity Consumers Resource Council, Large Public Power Council, National Rural Electric Cooperative Association
TVA	Tennessee Valley Authority

Document Content(s)

RM18-8-000.DOCX.....1-57

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

SUNSHINE ACT MEETING NOTICE

November 8, 2018

The following notice of meeting is published pursuant to section 3(a) of the government in the Sunshine Act (Pub. L. No. 94-409), 5 U.S.C. 552b:

AGENCY HOLDING MEETING:	FEDERAL ENERGY REGULATORY COMMISSION
DATE AND TIME:	November 15, 2018 10:00 A.M.
PLACE:	Room 2C 888 First Street, N.E. Washington, D.C. 20426
STATUS:	OPEN
MATTERS TO BE CONSIDERED:	Agenda * NOTE - Items listed on the agenda may be deleted without further notice.
CONTACT PERSON FOR MORE INFORMATION:	Kimberly D. Bose Secretary Telephone (202) 502-8400 For a recorded message listing items struck from or added to the meeting, call (202) 502-8627.

This is a list of matters to be considered by the Commission. It does not include a listing of all documents relevant to the items on the agenda. All public documents, however, may be viewed on line at the Commission's website at http://ferc.capitolconnection.org/ using the eLibrary link, or may be examined in the Commission's Public Reference Room.

1049th - MEETING

OPEN MEETING

November 15, 2018

10:00 AM

Item No	Docket No.	Company
		ADMINISTRATIVE
A-1	AD19-1-000	Agency Administrative Matters
A-2	AD19-2-000	Customer Matters, Reliability, Security and Market Operations
A-3	AD07-13-012	FY2018 Report on Enforcement
		ELECTRIC
E-1	RM19-5-000	Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes
E-2	RM19-4-000	Implementation of Amended Section 203(a)(1)(B) of the Federal Power Act
E-3	RM18-8-000 RM15-11-003	Geomagnetic Disturbance Reliability Standard Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events
E-4	PL19-2-000	Accounting and Ratemaking Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset
E-5	EL18-62-000	AEP Appalachian Transmission Company, Inc. AEP Indiana Michigan Transmission Company, Inc. AEP Kentucky Transmission Company, Inc. AEP Ohio Transmission Company, Inc. AEP West Virginia Transmission Company, Inc.
	ER18-1546-000	PJM Interconnection, L.L.C. AEP Appalachian Transmission Company, Inc. AEP Indiana Michigan Transmission Company, Inc. AEP Kentucky Transmission Company, Inc. AEP Ohio Transmission Company, Inc. AEP West Virginia Transmission Company, Inc.
	EL18-63-000	AEP Oklahoma Transmission Company, Inc. AEP Southwestern Transmission Company, Inc.
	ER18-1541-000	Southwest Power Pool, Inc.

	EL18-65-000 ER18-1583-000	Black Hills Power, Inc.
	EL18-70-000 ER18-1544-000 (not consolidated)	Transource West Virginia, LLC PJM Interconnection, L.L.C. Transource West Virginia, LLC
E-6	EL14-12-003	Association of Businesses Advocating Tariff Equity Coalition of MISO Transmission Customers Illinois Industrial Energy Consumers Indiana Industrial Energy Consumers, Inc. Minnesota Large Industrial Group Wisconsin Industrial Energy Group v. Midcontinent Independent System Operator, Inc. ALLETE, Inc. Ameren Illinois Company Ameren Missouri Ameren Transmission Company of Illinois American Transmission Company LLC Cleco Power LLC Duke Energy Business Services, LLC Entergy Arkansas, Inc. Entergy Gulf States Louisiana, LLC Entergy Louisiana, LLC Entergy Mississippi, Inc. Entergy New Orleans, Inc. Entergy Texas, Inc. Indianapolis Power & Light Company International Transmission Company ITC Midwest LLC Michigan Electric Transmission Company, LLC MidAmerican Energy Company Montana-Dakota Utilities Co. Northern Indiana Public Service Company Northern States Power Company-Minnesota Northern States Power Company-Wisconsin Otter Tail Power Company Southern Indiana Gas & Electric Company
	EL15-45-000	Arkansas Electric Cooperative Corporation Mississippi Delta Energy Agency Clarksdale Public Utilities Commission Public Service Commission of Yazoo City Hoosier Energy Rural Electric Cooperative, Inc. v. ALLETE, Inc. Ameren Illinois Company Ameren Missouri Ameren Transmission Company of Illinois American Transmission Company LLC Cleco Power LLC Duke Energy Business Services, LLC Entergy Arkansas, Inc. Entergy Gulf States Louisiana, LLC Entergy Louisiana, LLC Entergy Mississippi, Inc. Entergy New Orleans, Inc. Entergy Texas, Inc. Indianapolis Power & Light Company

		International Transmission Company ITC Midwest LLC Michigan Electric Transmission Company, LLC MidAmerican Energy Company Montana-Dakota Utilities Co. Northern Indiana Public Service Company Northern States Power Company-Minnesota Northern States Power Company-Wisconsin Otter Tail Power Company Southern Indiana Gas & Electric Company
E-7	EL18-71-000 EL18-71-001	UNS Electric, Inc.
E-8	EL18-72-000	Alcoa Power Generating Inc.- Long Sault Division
	EL18-73-000	Alcoa Power Generating Inc.- Tapoco Division
	ER18-1600-000 ER18-1601-000	Alcoa Power Generating Inc.
	EL18-76-000 ER18-1580-000	Black Hills/Colorado Electric Utility Company, LP
	EL18-90-000 ER18-1602-000	Cube Yadkin Transmission LLC
	EL18-97-000	Essential Power Rock Springs, LLC
	ER18-1566-000	PJM Interconnection, L.L.C. Essential Power Rock Springs, LLC
	EL18-101-000	Monongahela Power Company Potomac Edison Company West Penn Power Company
	ER18-1595-000	PJM Interconnection, L.L.C. Monongahela Power Company Potomac Edison Company West Penn Power Company
	EL18-102-000	Nevada Power Company Sierra Pacific Power Company
	ER18-1603-000	Nevada Power Company
	EL18-103-000	New York State Electric & Gas Corporation
	EL18-110-000	Rochester Gas and Electric Corporation
	ER18-1588-000	New York Independent System Operator, Inc. New York State Electric & Gas Corporation Rochester Gas and Electric Corporation
	EL18-105-000 ER18-1599-000 ER18-1599-001	Ohio Valley Electric Corporation
	EL18-117-000 ER18-1547-000 (not consolidated)	The Dayton Power & Light Company PJM Interconnection, L.L.C. The Dayton Power & Light Company
E-9	EL18-67-000	San Diego Gas & Electric Company
E-10	EL18-68-000	Transource Maryland, LLC
	EL18-69-000 (not consolidated)	Transource Pennsylvania, LLC
E-11	EL18-75-000	Avista Corporation

E-12	ER18-1596-000 EL18-112-000	Sky River LLC
E-13	EL18-93-000	Deseret Generation and Transmission Co-operative, Inc.
	EL18-113-000 (not consolidated)	Smoky Mountain Transmission LLC
E-14	EL18-79-000	Cheyenne Light, Fuel and Power Company
E-15	EL18-91-000	DATC Path 15, LLC
E-16	EL18-66-000	Citizens Sunrise Transmission LLC
E-17	EL18-108-000	Pacific Gas and Electric Company
E-18	EL18-111-000	Rockland Electric Company
	ER18-1585-000	PJM Interconnection, L.L.C. Rockland Electric Company
E-19	EL18-104-000	NorthWestern Corporation
E-20	EL17-41-001	Arkansas Public Service Commission and Mississippi Public Service Commission v. System Energy Resources, Inc.
	EL18-142-000 (Consolidated)	Louisiana Public Service Commission v. System Energy Resources, Inc. and Entergy Services, Inc.
	EL17-76-001	East Texas Electric Cooperative, Inc. v. Public Service Company of Oklahoma; Southwestern Electric Power Company; AEP Oklahoma Transmission Company; and AEP Southwestern Transmission Company
	EL18-58-000	Oklahoma Municipal Power Authority v. Oklahoma Gas and Electric Company
	ER18-1225-000	Southwestern Electric Power Company
	EL18-122-000 (Consolidated)	Minden, Louisiana v. Southwestern Electric Power Company
	EL18-147-000	Alabama Municipal Electric Authority and Cooperative Energy v. Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; and Southern Company Services, Inc.
E-21	EL18-119-000	Tucson Electric Power Company
E-22	EL18-64-000	Baltimore Gas and Electric Company
E-23	EL18-115-000	Startrans IO, L.L.C.
E-24	EL18-118-000	Trans Bay Cable LLC
E-25	EL18-183-000	Radford’s Run Wind Farm, LLC v. PJM Interconnection, L.L.C.
E-26	AC18-59-000	Edison Electric Institute
E-27	ER18-2273-000	Midcontinent Independent System Opeator,Inc.

E-28	ER18-1788-000	MATL LLP
E-29	EL18-89-000	Consolidated Edison Company of New York, Inc.
E-30	EL18-95-000	El Paso Electric Company
E-31	EL18-98-000	Florida Power & Light Company
E-32	EL18-107-000	Orange & Rockland Utilities, Inc.
E-33	EL18-109-000	Portland General Electric Company

GAS

G-1	RM96-1-041	Standards for Business Practices of Interstate Natural Gas Pipelines
G-2	RP19-65-000 RP19-66-000	Millennium Pipeline Company, L.L.C.
G-3	OMITTED	
G-4	RP19-71-000 RP19-72-000	North Baja Pipeline, LLC
G-5	RP19-60-000 RP19-61-000	Vector Pipeline L.P.
G-6	RP19-55-000 RP19-76-000	Kern River Gas Transmission Company
G-7	RP18-1219-000	Northern Natural Gas Company

HYDRO

H-1	P-2035-104	City and County of Denver, Colorado

CERTIFICATES

C-1	CP18-26-000	Texas Eastern Transmission, LP

Kimberly D. Bose,
Secretary.

A free webcast of this event is available through http://ferc.capitolconnection.org/. Anyone with Internet access who desires to view this event can do so by navigating to www.ferc.gov's Calendar of Events and locating this event in the Calendar. The event will contain a link to its webcast. The Capitol Connection provides technical support for the free webcasts. It also offers access to this event via television in the DC area and via phone bridge for a fee. If you have any questions, visit http://ferc.capitolconnection.org/ or contact Shirley Al-Jarani at 703-993-3104.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in the Commission Meeting Room. Members of the public may view this briefing in the designated overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

November 2018
Commission Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its November 15, 2018 public meeting. The summaries are produced by FERC's Office of External Affairs and are intended to provide only a general synopsis of the orders. These summaries are not intended as a substitute for the Commission's official orders. To determine the specific actions and the Commission's reasoning, please consult the individual orders when they are posted to FERC's eLibrary found at www.ferc.gov.

Press Release – A-3

Press Release - E-1, E-4, E-5, E-7 through E-19, E-21 through E-24, E-26, E-29 through E-33, G-2, and G-4 through G-6

FERC proposes a rule

E-2, *Implementation of Amended Section 203(a)(1)(B) of the Federal Power Act*, Docket No. RM19-4-000. This Notice of Proposed Rulemaking (NOPR) proposes to revise section 33.1 of the Commission's regulations to add a $10 million threshold for mergers or consolidations by a public utility under amended section 203(a)(1)(B) of the Federal Power Act (Act). In addition, as required by the Act, this NOPR proposes to add section 33.12 to the Commission's regulations to establish a notification requirement for mergers or consolidations by a public utility if the facilities to be acquired have a value in excess of $1 million and such public utility is not required to secure Commission authorization under amended section 203(a)(1)(B).

FERC approves a reliability standard

E-3, *Geomagnetic Disturbance Reliability Standard; Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, Docket Nos. RM18-8-000, RM15-11-003. This final rule addresses proposed Reliability Standard TPL-007-2 (Transmission System Planned Performance for Geomagnetic Disturbance Events) submitted by the North American Electric Reliability Corporation (NERC). The proposed Reliability Standard was developed and submitted by NERC in response to a Commission directive in Order No. 830 to modify currently effective Reliability Standard TPL-007-1. The final rule also addresses the revised Geomagnetic Disturbance research work plan submitted by NERC in response to a Commission order issued on October 19, 2017.

FERC proposes a new methodology for MISO transmission owners' ROE

E-6, *Association of Businesses Advocating Tariff Equity v. Midcontinent Independent System Operator, Inc.*, Docket No. EL14-12-003, and *Arkansas Electric Cooperative Corporation v. ALLETE, Inc.*, Docket No. EL15-45-000. This order proposes to adopt the return-on-equity (ROE) methodology first proposed in the Commission's October 16, 2018 decision in *Martha Coakley v. Bangor Hydro-Electric Co.* (Docket No. EL11-66-001, *et al.*) (*Coakley*) to address the issues that the U.S. Court of Appeals for the District of Columbia Circuit remanded to the Commission in *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017). The order establishes a paper hearing on whether and how the ROE methodology proposed in *Coakley* should apply to the two complaint proceedings pending before the Commission involving the MISO transmission owners' ROE.

FERC provides guidance on pending proceedings involving base rate-of-return-on-equity issues

E-20, *Arkansas Public Service Commission, et al. v. System Energy Resources, Inc. et al.*, Docket No. EL17-41-001, *et al*. The order provides guidance regarding the effect of the Commission's October 16, 2018 decision in *Martha Coakley v. Bangor Hydro-Electric Co.* (Docket No. EL11-66-001, *et al.*) (*Coakley*) on pending proceedings involving base rate-of-return-on-equity issues that have been set for hearing and settlement judge procedures. The order clarifies that such ongoing proceedings do not need to be held in abeyance until the Commission issues a post-briefing order in the *Coakley* proceeding, and that the Commission does not intend to recall such proceedings back to the Commission for further consideration.

FERC grants, in part, a complaint; establishes paper hearing procedures

E-25, *Radford's Run Wind Farm, LLC v. PJM Interconnection, L.L.C.*, Docket No. EL18-183-000. Radford's Run Wind Farm, LLC filed a complaint against PJM stating that PJM did not determine or certify Incremental Capacity Transfer Rights (ICTR) as a result of the System Impact Study for its interconnection request. This order grants the Complaint, in part, and establishes paper hearing procedures to allow PJM to assess whether the Radford Upgrade increased the Capacity Emergency Transfer Limit of a Locational Deliverability Area and thus is eligible for ICTRs.

FERC grants a limited, one-time waiver

E-27, *Midwest Independent Transmission System Operator, Inc.*, Docket No. ER18-2273-000. The order grants MISO's request for a limited one-time waiver of Part B of Schedule 44 of its Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff), which requires that MISO conduct a quarterly Voltage and Local

Reliability (VLR) Allocation Study using MISO data from the prior 12 months before designating VLR Commitments as "commercially significant."

FERC clarifies previous ruling

E-28, *MATL LLP*, Docket No. ER18-1788. This order grants MATL's request for clarification regarding the applicability of Order No. 842 to a single existing interconnection customer already in its interconnection queue.

FERC approves a final rule that amends business practice standards

G-1, *Standards for Business Practices of Interstate Natural Gas Pipelines*, Docket No. RM96-1-041, *Final Rule; Order No. 587-Y*. The order amends the Commission's regulations at 18 CFR 284.12 to incorporate by reference, with certain enumerated exceptions, the latest version (Version 3.1) of business practice standards applicable to interstate natural gas pipelines adopted by the Wholesale Gas Quadrant of the North American Energy Standards Board in place of the currently incorporated version (Version 3.0) of those business practice standards. Under this final rule, interstate natural gas pipelines are required to file compliance filings with the Commission by April 1, 2019 and are required to comply with the standards incorporated by reference in this rule on and after August 1, 2019.

FERC grants a temporary and limited waiver

G-7, *Northern Natural Gas Co.*, Docket No. RP18-1219-000. This order grants temporary and limited waiver of 18 C.F.R. § 284.12(b)(2)(i) (2018), which requires that a pipeline enter into an Operational Balancing Agreement at all points of interconnection between its system and the system of another interstate or intrastate pipeline.

FERC denies rehearing

H-1, *City and County of Denver, Colorado*, Project No. 2035-104. The order denies Save the Colorado's request for rehearing of the Commission's notice denying Save the Colorado's late motion to intervene in the amendment proceeding of the City and County of Denver's Gross Reservoir Project, finding that Save the Colorado failed to show good cause for filing its intervention request late.

FERC conditionally approves abandonment and replacement of natural gas facilities

C-1, *Texas Eastern Transmission, LP*, Docket No. CP18-26-000. The order issues a certificate of public convenience and necessity and approves abandonment for Texas Eastern's proposed Lambertville East Expansion Project. Texas Eastern proposes to

replace two existing compressor units at its Lambertville Compressor Station in Hunterdon County, New Jersey. The project is designed to allow Texas Eastern to provide an additional 60,000 dekatherms per day of firm transportation service from interconnections in Lambertville, New Jersey, and Marietta, Pennsylvania, to existing city gates in New Jersey.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Incorrect Field Modification and RAS Operation Lead to Partial System Collapse

Primary Interest Groups
Balancing Authorities (BAs)
Reliability Coordinators (RCs)
Transmission Operators (TOPs)
Transmission Owners (TOs)
Generator Operators (GOPs)
Generator Owners (GOs)

Problem Statement
During an outage to isolate a 500 kV line disconnect switch and install a temporary bypass to facilitate its replacement, the position of an auxiliary contact multiplier relay was incorrectly modified by field staff. This incorrect multiplier position enabled line stub bus protection, which misoperated due to the increase in flow despite there being no actual line fault. This incorrect multiplier position also prevented the remedial action scheme (RAS) from operating as designed for the loss of the respective 500 kV circuit. The actuations resulted in separation of a large portion of the entity's system, load losses, generator trips, and islanding of a small pocket sustained by local generation.

Details
On August 9, 2017, planned work was underway to replace the 500 kV Line A disconnect switch at Station A. As part of this project, a temporary bypass was installed to keep the circuit in-service during the replacement (see Figure 1).

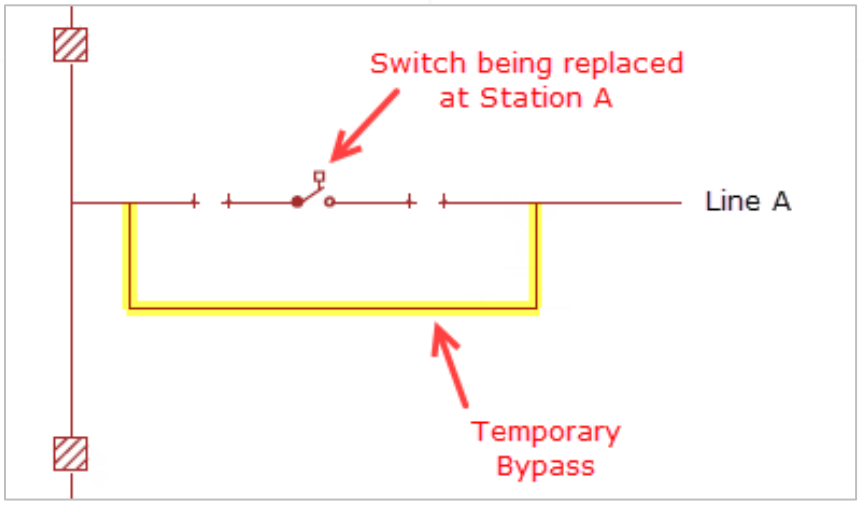


Figure 1: Schematic of Disconnect Switch and Bypass at Station A

Believing that the Line A disconnect switch was in the open position (as is typical for line outages), the Field Protection & Control (P&C) staff member toggled the position of an auxiliary contact multiplier relay to maintain protection adequacy of Line A with the bypass circuit in-service. The intention was to simulate the switch in the closed position to the protection relays during the month-long line disconnect replacement. The P&C personnel was not aware that the disconnect switch was requested closed during this period to facilitate its removal due to clearance issues. During this modification, the physical position of the disconnect switch was not verified and neither was the OPEN & CLOSED labeling on the auxiliary multiplier relays to confirm the current line switch position. Due to this incorrect assumption, this action resulted in the auxiliary contact multiplier being placed in the opposite position, indicating to the protective relays that the disconnect switch was open. The circuit, along with the bypass, was then placed back in-service in the early hours on August 10.

With the circuit in-service and the line disconnect switch being indicated as open to the protection relays, the line stub bus protection was enabled and the detection of a Line A contingency in the RAS became disabled as designed after one second. The TO does not normally receive any indication when a RAS contingency becomes disabled. By mid-day, as generation and flows in the region increased, the power flow on Line A exceeded the stub bus protection pickup threshold; this, combined with the perceived open disconnect switch, looked exactly like a major fault to the protection system and resulted in the undesirable trip of the Line A terminal breakers at Station A.

When the Line A contingency occurred, the RAS was armed to trip Line B, Line C, Line D, some generation, and large industrial loads in the region (see Figure 2). An assessment by the RC indicated that the arming of the RAS was correct based on the system conditions at the time. However, the RAS did not trip as expected (Line B remained in service) due to the detection of a Line A contingency being previously disabled. Instead, Line B tripped from overvoltage protection 58 seconds after the initial contingency. A security feature of the RAS prevents it from detecting the Line A contingency after one second following its initiation.

With the significant imbalance of the generation and load in the area, Line E and Line F protections operated during load swings into the relay trip settings. Line G “B” line protection was an intelligent electronic device (IED) type with an older firmware version that operated at about 61.7 hertz. Line H and I “B” line protections operated at above 65 hertz.

The actuations resulted in separation of a large portion of the entity’s system, load losses, generator trips, and islanding of a small pocket sustained by local generation as indicated on the following diagram.

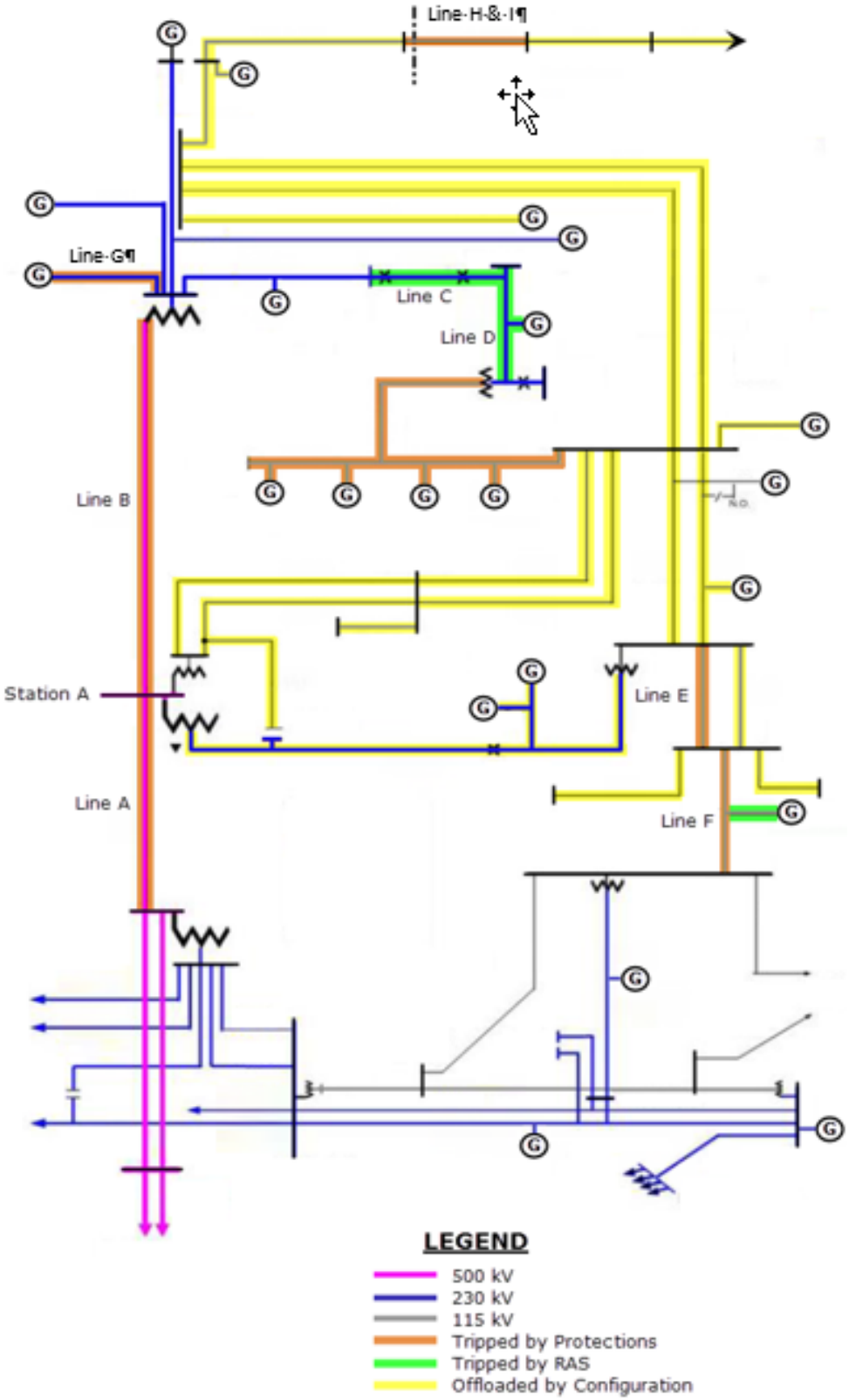


Figure 2: Single Line Diagram of the Affected Region

Corrective Actions (as performed by the entity)

- The position of the auxiliary multiplier was corrected for the Line A disconnect switch.
- Although it is common practice to verify the status of equipment when performing auxiliary isolation/switching, it was not clearly stated in the process documents. These documents will be revised to clearly state that a status check (both primary and auxiliary devices) must be performed prior to operating auxiliary devices.
- The event was reviewed with all control room staff and field staff to re-enforce the importance of clear communication and verifying device status during switching.
- The functionality of the Line B cross-trip scheme was tested to verify that it works within acceptable timings.
- Line E and Line F protections operated during a power swing for which a study will be done to verify the possibility of improving immunity during a similar event.
- For one of the relay misoperations (Line G), the issue was determined to be a limitation of the relay design associated with an older firmware version which may cause misoperation during frequency excursions. The relay manufacturer advised that newer firmware versions provide a user settable parameter that, if set correctly, could have avoided this misoperation.
- For the other misoperation on a different relay type (Line H & I), a setting modification was suggested by the vendor and is being incorporated by the TO. This is the only location where these relays were set in this manner and new protection relay settings have been issued to the field.
- The viability of adding an alarm point to monitor RAS contingency status for critical BES elements will be explored.

Lessons Learned

- Ensure field staff always verify the status of the equipment prior to making changes on an auxiliary contact multiplier and include this in your procedures if it doesn't already exist.
- Reinforce proper communications between control room staff and field P&C staff so that both parties understand the purpose of the auxiliary switching.
- Consider adding an alarm or status change when a RAS Contingency is inadvertently blocked by any means other than the "Master Block" control point.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

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