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 #16-6
December 8, 2016 8:00 a.m. – 5:00 p.m. EST
December 9, 2016 8:00 a.m. – 12:00 p.m. EST
Hotel Omni Mont-Royal: Room Automne
1050 Sherbrooke Street West
Montreal, Quebec H3A 2R6
Attire: Business Casual

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

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated September 29, 2016
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 Hydro Quebec GMD Studies
5.3 RSC Work Plan 2017-2018
5.4 RSC Scope of Work 2017-2018

6.0 NERC Reliability Standards

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

6.1 Currently Posted Projects

Project	Comment Period End Date	Ballot Period End Date	Standards Developer	12/8/16 Call-In
Project 2013-03 Geomagnetic Disturbance Mitigation Revisions to Project White Papers	6/13/16 (I)	NA	Mark Olson	1:00PM
Project 2016-01 Modifications to TOP and IRO Standards	10/17/16 (F)	10/17/16 (A)	Mark Olson	1:15PM
Project 2016-03 Cyber Security Supply Chain Management SAR	11/18/16 (I)		Mark Olson	1:30PM
Project 2016-02 Modifications to CIP Standards	12/5/16 (F)	12/5/16 (A)	Al McMeekin	1:45PM
Project 2015-09 Establish and Communicate System Operating Limits	8/12/16 (I)	NA	Lacey Ourso	2.00PM
Functional Model Advisory Group	9/7/16 (I)	NA	Lacey Ourso	2:15PM
Project 2015-08 Emergency Operations EOP-004-4	9/8/16 (F)	9/8/16 (I)	Laura Anderson	2:30PM
Project 2015-10 Single Points of Failure TPL-001	6/24/16 (I)	SAR	Jordan Mallory	2:45PM
Project 2016-04 Modifications to PRC-025-1	10/18/16 (F)		Scott Barfield-McGinnis	3:00PM
Revisions to the NERC Standard Processes Manual	10/28/15 (I)	NA	Guy Zito	3:15PM
Enhanced Periodic Review Standing Review Team - Standards Grading	8/1/16 (I)	NA	Mat Bunch	3:30PM
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 FERC Approved the Retirement of PRC-002-NPCC-01

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

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

8.1.4 Geomagnetic Disturbance Mitigation TPL-007-1 Quebec Variance

9.0 NPCC Non-Standards

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

9.1 Directories:

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

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

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

- RAS Implementation/Transition.

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

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

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

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

9.1.7 Criteria Clarifications;

- Directory#4 *System Protection Criteria* (Pending Request for Clarification—TFSP)

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 21st - Call	March 9th - Meeting	April 20th - Call
June 15th - Meeting	July 20th - Call	September 14th Meeting
October 19th - Call	December 14th - Meeting	

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

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

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

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

12.6 Reliability Issues Steering Committee (RISC)
http://www.nerc.com/comm/RISC/Pages/AgendasHighlightsandMinutes.aspx

13.0 NERC Items of Interest (Since last RSC Meeting)

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

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

13.2 Alerts

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

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

13.3 Second Draft of 2017 Business Plan and Budget

13.4 Standard Committee 2017 Meeting Schedule

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

13.5 Notice of Proposed Revisions to NERC Rules of Procedure

14.0 Other Items of Interest

14.1 NPCC Compliance Committee (CC) Schedule

January 13th – Call	February 17th – Call	March 15-16th Meeting
April 13th – Call	May 10-12th Workshop	June 21-2nd Meeting
July 13th – Call	August 17th – Call	September 20-21st Meeting
October 12th – Call	November 15-17th Workshop	December 8-9th Meeting

14.2 NPCC Board of Directors Meeting (BOD) 2016

February 2nd – Control Center Tour February 3rd - IESO Offices	March 23rd – Call	April 27th – NPCC Offices
June 2nd – Call	June 29th – NPCC Offices	August 3rd - Call
September 7th – NPCC Long Range Strategy Session September 8th – NPCC Offices	October 25th – Call	December 7th – Montreal, Quebec

14.3 NPCC Board of Directors Meeting (BOD) 2017

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

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2016 Meeting Dates

February 17th-18th, NextEra Energy Offices, Juno Beach FL
April 19th & 20th, NPCC Offices, New York NY
June 22nd & 23rd, Saratoga NY
August 10th & 11th, Toronto Canada
October 5th & 6th, Lewiston NY
December 8th & 9th, Montreal Canada

RSC 2017 Meeting Date

March 8th-9th, FRCC, Tampa FL
June 7th-8th, Saratoga NY
August 23rd-24th, Toronto/Montreal
October 11th-12th, Lewiston NY
December 7th, General Meeting

15.2 RSC 2016 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 8	January 22	February 5
March 4	March 18	April 1
April 29	May 13	May 27
June 10	July 8	July 22

August 5	September 2	September 16
September 30	October 21	November 4
November 18	December 23	

Respectfully Submitted,

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

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

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

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

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

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

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

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

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NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #16-5
October 5, 2016 10:00 a.m. – 5:00 p.m. EST
October 6, 2016 8:00 a.m. – 3:00 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) **Guest Code: 28840965**

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated August 17, 2016
NPCC Glossary of Terms, dated January 14, 2014

	Name	Organization	Sector (s)	Day(s)	Comment
1.	Guy Zito	Northeast Power Coordinating Council		1 & 2	
2.	Gerry Dunbar	Northeast Power Coordinating Council		1 & 2	
3.	Ruida Shu	Northeast Power Coordinating Council		1 & 2	
4.	Al McMeekin	NERC	Guest	1 & 2	
5.	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	1 & 2	
6.	Michael Jones	National Grid	3	1 & 2	
7	Brian Shanahan	National Grid	1	1	
8.	Joel Charlebois	AESI, Inc.	Guest	1 & 2	
9.	Ron Falsetti	AESI, Inc.	Guest	1 & 2	
10.	Kelly Silver	Consolidated Edison Co. of New York, Inc.	1, 3, 4 & 5	1 & 2	
11.	David Ramkalawan	Ontario Power Generation, Inc.	4	1 & 2	
12.	Si Truc Phan	Hydro-Québec TransÉnergie	2	1 & 2	
13.	Glen Smith	Entergy Services, Inc	4	1 & 2	
14.	Jim Grant	New York Independent System Operator	2	1 & 2	

15.	Payam Farahbakhsh	Hydro One Networks	1	1	
16.	Ben Wu	Orange & Rockland Utilities, Inc.	3	1 & 2	
17.	Salvatore Spagnolo	New York Power Authority	4	1 & 2	
18.	Quintin Lee	Eversource Energy	1	1 & 2	Via Phone
19.	Sean Bodkin	Dominion Resources Services	4	1 & 2	Via Phone
20.	Michele Tondalo	The United Illuminating Company	1	1 & 2	Via Phone
21.	Brian Robinson	Utility Services, Inc.	5	1 & 2	Via Phone
22.	David Kiguel	Independent	Guest	1 & 2	Via Phone
23.	Damase Hebert	Northeast Power Coordinating Council		1	Via Phone
24.	Dermot Smyth	Consolidated Edison Co. of New York, Inc.	3	2	Via Phone
25.	Mark Olson	NERC	Guest	1	Via Phone
26.	Laura Anderson	NERC	Guest	1	Via Phone
27.	Scott Barfield-McGinnis	NERC	Guest	1	Via Phone
28.	Jordan Mallory	NERC	Guest	1	Via Phone
29.	Lauren Perotti	NERC	Guest	1	Via Phone
30.	Mat Bunch	NERC	Guest	1	Via Phone

Introductions and Chair's Remarks

Guy Zito welcomed all the members of RSC to NYPA's Power Vista and thanked Salvatore Spagnolo for hosting the meeting.

Guy Zito provided background on the nomination of Mike Jones to the position of vice chair of RSC.

Mike Jones of National Grid was nominated to the position of Co-Vice Chairperson of RSC by unanimous consent pending approval by the NPCC BOD.

Guy Zito congratulated Mike Jones on his nomination.

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 agenda with the RSC and added agenda item 5.9 Discussion of MOD-028, MOD-029 and MOD-30 per the request of Si Truc Phan.
Agenda moved forward by unanimous consent.

2.0 RSC Meeting Minutes

The Final Meeting Minutes of 8-10-16 were approved as read by unanimous decision.

3.0 Drafting Team Members and Executive Tracking Summary

3.1 NPCC Members on NERC Drafting Teams

Ruida Shu updated the RSC Members on NERC Drafting Team spreadsheet.

3.2 Executive Tracking Summary

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

3.3 NERC Project Tracking Spreadsheet

Ruida Shu provided a brief update on the NERC Project Tracking Spreadsheet.

4.0 Open Action Items

4.1 Open Action Items List

1. Utility Services submitted a SAR on the CIP-014 auditor practice guide and it was not accepted by NERC. NERC believes that similar situations can be dealt with on a case by case.
Guy Zito suggested that additional feedback on the CIP-014 auditor practice regarding physical security perimeter could be provided.
The requirement lacks clarity and needs additional guidance on Implementation period for an entity that identifies a facility subject to the standard after the implementation plan for the standards requirements expires.
Action Item: The RSC will pursue additional information on CIP-014 Compliance implementation period for newly applicable Transmission Owners.
2. Hydro Quebec is in the middle of a study on GMD. The goal is to incorporate the study results to the new version of the standard.

5.0 Items Requiring RSC Discussion

5.1 NERC Weekly Standards Bulletin

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

5.2 RSC Scope of Work

Guy Zito reviewed a draft of the RSC Scope of Work which had been circulated to the RSC for comments. Ruida Shu will send a redline draft to the RSC for final comments.

Herb Schrayshuen provided some insight on the rules for missing meetings. He suggested if you were to miss three meetings then you shall be removed from the RSC roster. Possible duration time and verbal warning were suggested.

The RSC will provide their comments prior to October 21, 2016.

5.3 RSC Work Plan

Guy Zito reviewed a draft of the RSC Work Plan which had been circulated to the RSC for comments. Ruida Shu will send a redlined draft to the RSC for final

comments. Guy Zito stated that he would like to finalize the Work Plan October 21, 2016 in order to present to the NPCC BOD.

5.4 GMD FERC Order

Guy Zito provided the RSC with a presentation on GMD.

Highlights of presentation included:

FERC Order 830 approved TPL-007-1 and contained three Directives:

1. NERC to modify the calculation of the benchmark GMD so that the calculation is not based solely on spatial averaging;
2. Revisions to the Standard requiring entities to collect and make available GIC monitoring data to be used in planning and operations;
3. Revisions to the Standard requiring specific deadlines for Corrective Action Plan.

5.5 IRO-018-1/TOP-010-1 FERC Order

5.6 NPCC Regional Feedback Mechanism Process

Damase Hebert from NPCC called into the meeting at 11AM.

Damase Hebert thanked the RSC for their prior comments and stated that a number of RSC suggestions have been incorporated into the process.

The goal is to finalize the process in mid-October 2016. There will be a feedback loop page along with a tracking sheet on the NPCC website.

Guy Zito asked for a motion to endorse the NPCC Regional Feedback Mechanism Process document.

Herb Schrayshuen made a motion for approval.

Michael Jones seconded the motion.

The NPCC Regional Feedback Mechanism Process is approved as read.

5.7 NPCC CC Process for Submitting Implementation Guidance

Damase Hebert reviewed the Process for Submitting Implementation Guidance.

Guy Zito expressed concern with aspects of the process that would permit a stakeholder to request that implementation guidance be developed instead of vetting an approach that has already been utilized for compliance.

The goal is to have the Implementation Guidance document reviewed by the appropriate task forces first before presenting it to the RSC. There are some concerns in regards to the lack of formal process to the Implementation Guidance.

Guy Zito also expressed concern regarding that portion of the process that utilized NPCC Task Forces since the Task Forces are generally unaware of this process and may have some reluctance in providing a technical recommendation that will be used for compliance purposes.

Damase Hebert agreed to consider final RSC comments before finalizing the Implementation Guidance process with the CC.

Herb Schrayshuen provided a comment on MRO's utilization of the of the Compliance Implementation Guidance Processes.

5.8 Project 2016-03 Cyber Security Supply Chain Management

Guy Zito provided the RSC with a presentation on Cyber Security Supply Chain Management.

Highlights of the presentation included:

NERC to develop a new or modified standard by August 2017, CIP Supply Chain to consider:

1. Software integrity ad authenticity
2. Vendor Remote Access
3. Information System Planning
4. Vendor Risk Management and Procurement Controls

5.9 MOD-028, MOD-029 and MOD-030

Hydro Quebec requested a discussion on the MOD- 'A' Standards and which of the three different methodologies are used in NPCC.

NPCC uses MOD-29 (Rated Path)

Hydro Quebec considering which of three standards to file with the Regie.

6.0 NERC Reliability Standards

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

6.1 Currently Posted Projects

Project	Comment Period End Date	Ballot Period End Date	Standards Developer	10/5/16 Call-In
Project 2015-10 Single Points of Failure TPL-001	6/24/16 (I)	SAR	Jordan Mallory	1:00PM
Project 2016-01 Modifications to TOP and IRO Standards	10/14/16 (F)	10/14/16 (A)	Mark Olson	1:15PM
Project 2016-03 Cyber Security Supply Chain Management			Mark Olson	1:30PM
Project 2015-INT-01 Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	9/12/16 (F)	9/12/16 (I)	Al McMeekin	1:45PM In Person
Project 2016-02 Modifications to CIP Standards	9/6/16 (F)	9/6/16 (I)	Al McMeekin	2:00PM In Person
Project 2015-09 Establish and Communicate System Operating Limits	8/12/16 (I)	NA	Lacey Ourso	2:15PM
Functional Model Advisory Group	9/7/16 (I)	NA	Lacey Ourso	2:30PM
Project 2015-08 Emergency Operations EOP-004-4, EOP-005-3, EOP-006-3 and EOP-008-2	9/8/16 (F)	9/8/16 (I)	Laura Anderson EOP SDT	3:45PM
Project 2013-03 Geomagnetic Disturbance Mitigation Revisions to Project White Papers	6/13/16 (I)	NA	Mark Olson	3:00PM
Project 2016-04 Modifications to PRC-025-1	10/18/16 (F)		Scott Barfield-McGinnis	3:15PM
Revisions to the NERC Standard Processes Manual	10/28/15 (I)	NA	Lauren Perotti	3:30PM
Enhanced Periodic Review Standing Review Team - Standards Grading	8/1/16 (I)	NA	Mat Bunch	2:45PM
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period				

Project 2015-10 Single Points of Failure:
Jordan Mallory from NERC called in at 12:54PM.
The purpose of the project is to address the 1600 data request on single points of failure.
The project is also intended to address FERC Order-s 786. The replacement of the word “relay” to “protection system component”.
The first SDT team meeting will be in November 2016.
The majority of the standard drafting team members are composed of SAMS members.

Project 2016-01 Modifications to TOP and IRO Standards:
Mark Olson from NERC called in at 1:17PM.
The project is currently posted for a second comment period.
The FERC Order due day is July of 2017.
Three directives were issued in Order# 817. Monitoring of non BES facilities, redundancy of diverse routing, data exchange and the testing of these.
The standard is posted through October 14, 2016.

Project 2016-03 Cyber Security Supply Chain Management:
Mark Olson discussed the need to have this project.
The standard drafting team has been selected.
The SAR is submitted to the Standards Committee for approval to post.
The first SDT meeting will be on October 17-19, 2016 in Atlanta GA.
There are four objectives to address the FERC Directive.
The goal is to have a technical conference towards the end of the year.
Target due date is August 2017.

Project 2013-03 Geomagnetic Disturbance Mitigation:
The commission has approved TPL-007.
Implementation plan is also approved and it is moving forward.
The effective date of TPL-007 is January 2017. There is a (6 month) implementation period and the standard will be enforceable on July 2017.
FERC has issued some very specific directives on the standard.
Very challenging to collect the GIC data, but it is necessary for the model validation.
Asset owners will be responsible to collect the GIC data.
There is a requirement for NERC to file the GMD research plan by May 2017.
The deadline for the revision and post is 18 months.
The SDT is soliciting additional members to join their team.

Project 2015-09 Establish and Communicate System Operating Limits:
Lacey Ourso was not available to call in to discuss Project 2015-09.

Functional Model Advisory Group:
Lacey Ourso was not available to call in to discuss Functional Model Advisory Group.

Project 2015-INT-01 Interpretation of CIP-002-5.1 for Energy Sector Security (Energy Sec):
Al McMeekin discussed the interpretation with the RSC.
Industry agreed with the interpretation and had an approval rate of 92 percent.
The SDT has responded to all the comments and did not change any of the responses to the document.

Project 2016-02 Modifications to CIP Standards:
Al McMeekin gave a brief presentation on the latest status of Project 2016-02.

Enhanced Periodic Review Standing Review Team:
Mat Bunch called into the RSC meeting at 2:49PM.
There is a separate SME team taking the grade and refining the details of the standard.
The final grade will be attached to the Reliability Standards Development Plan.
The Reliability Standards Development Plan will be presented to the Board for approval.
The SME will submit their recommendation to the SC and if SC approve the recommendation then Projects will be developed based on the grading.

Project 2016-04 Modifications to PRC-025-1:
Scott Barfield from NERC called into the RSC meeting at 2:54PM.
The SAR is developed to address the issues that came up during the implementation period. Issues such as stability with wind turbines.
Generators connected to a long transmission line is another concern.

Revisions to the NERC Standard Processes Manual:
Lauren Perotti called into the RSC meeting at 3:21PM.
SC endorsed the changes to Section 6 to the NERC Standard Processes Manual.
Changes to section 6 are specific to the standing committee to have the ability to stop the field test if there is a reliability concern.
Section 11 needs additional revision since there is some overlap with the CMEP implementation.
The target is to move forward section 6, 7 and 11 all together for approval.
SC approved its charter with Mexico and NERC legal is working on some revisions to the charter.
Currently there is one representative from Mexico.

Project 2015-08 Emergency Operations:
Laura Anderson and the entire SDT called in at 3:43PM.
Most of the comments were targeted towards the attachment.
The SDT have reviewed EOP-005, EOP-006 and EOP-008 and they plan to review the comments for EOP-004 tomorrow.

The SDT decided to keep the plan and unplanned BES system modification separated in order to clarify the plan, unplanned and the trigger.
The SDT removed the word “maintain” in the requirement.
The SDT is aiming to post towards the end of October 2016.

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 FERC Approved the Retirement of PRC-002-NPCC-01
- 8.1.2 Automatic Underfrequency Load Shedding PRC-006-NPCC-02 status update

  Ruida Shu provided a brief update on the status of PRC-006-NPCC-02.
- 8.1.3 Approval of Final Draft PRC-006-3 Automatic Underfrequency Load Shedding Quebec Variance for 45-day comment period posting

  Herb Schrayshuen made a motion to approve the posting.

  Mike Jones seconded the motion.

  Final Draft PRC-006-3 Automatic Underfrequency Load Shedding Quebec Variance is approved for a second 45-day comment period posting.
- 8.1.4 Geomagnetic Disturbance Mitigation TPL-007-1 Quebec Variance

9.0 NPCC Non-Standards

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

9.1 Directories:

Gerry Dunbar updated the RSC on Directory status:

- 9.1.1 Directory#8 *System Restoration* – (status of CO11 review).

  Posted for second Open Process posting which concludes on October 15th, 2016. TFCO has revised the battery testing criteria in Directory#8 in consideration of recently approved PRC-005-2.

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

TFCO is considering a retirement recommendation by its Working Group CO-7 which concluded the Directories can be retired upon the full enforcement of MOD-025-2.

9.1.3 Directory#7 *SPS* and NPCC Glossary term SPS – (status of PRC -12-2 and Task Force review of SPS transition.)

PRC-012-2 has been filed with FERC. TFCP will coordinate the transition from SPS to RAS among other Task Forces within NPCC. TFSS currently reorganizing the NPCC SPS list into:1) SPS's that conform to definition of RAS; 2) SPS's that do not conform to definition of RAS; 3) newly identified protection systems that conform to the RAS definition but are not on the SPS list and have not been subject to a regional review.

TFCP has also requested that TFSS rename the SPS list to RAS/SPS list.

Pending FERC action on PRC-012-2 subsequent transition steps will be implemented (NPCC document review and Directory#7 Criteria review).

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

TFCP formalizing scope of review to be assigned to the CP-011 Working Group.

CP-11 review to begin early 2017.

9.1.5 Directory#11 *Disturbance Monitoring Equipment Criteria* – (status)

Directory#11 posted for Full Member approval ballot until October 24, 2016.

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

- RSC to consider incorporating A-01 into the Directory Review and Revision Manual
  TFCP reviewing document A-01 including comments from NPCC Task Forces.

  Upon completion of this review, which will include an additional posting and ultimately a Full Member approval ballot), Mr. Dunbar suggested retiring the A-01 and incorporating its contents as either an Attachment or an Appendix in the Directory Manual. The RSC has jurisdiction over revisions to the Directory Manual.

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

TFCO to begin review of each Directory early 2017.

9.1.8 Criteria Clarifications;

- Directory#4 *System Protection Criteria* (Pending Request for Clarification—TFSP)

  Posted to the Open Process for comments until November 17th, 2017.

- Directory#5 *Reserve* – (TFCO Clarification RCC Approved September 7th, 2016).

  Approved by the RCC September 7th, 2016.
- Directory#1 *Design and Operation of the BPS* – (TFCP Clarification RCC Approved September 7th, 2016)

  Approved by the RCC September 7th, 2016.

10.0 RSC Member Items of Interest

10.1 RSC Roster

The RSC Members reviewed the current RSC roster for changes.
NYPA and Hydro Quebec will send updates to Ruida Shu.

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 21st - Call	March 9th - Meeting	April 20th - Call
June 15th - Meeting	July 20th - Call	September 14th Meeting
October 19th - Call	December 14th - Meeting	

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

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

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

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

12.6 Reliability Issues Steering Committee (RISC)
http://www.nerc.com/comm/RISC/Pages/AgendasHighlightsandMinutes.aspx

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

13.3 Second Draft of 2017 Business Plan and Budget

13.4 Standard Committee 2017 Meeting Schedule

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

14.0 Other Items of Interest

14.1 NPCC Compliance Committee (CC) Schedule

January 13th – Call	February 17th – Call	March 15-16th Meeting
April 13th – Call	May 10-12th Workshop	June 21-2nd Meeting
July 13th – Call	August 17th – Call	September 20-21st Meeting
October 12th – Call	November 15-17th Workshop	December 8-9th Meeting

14.2 NPCC Board of Directors Meeting (BOD) 2016

February 2nd – Control Center Tour February 3rd - IESO Offices	March 23rd – Call	April 27th – NPCC Offices
June 2nd – Call	June 29th – NPCC Offices	August 3rd - Call
September 7th – NPCC Long Range Strategy Session September 8th – NPCC Offices	October 25th – Call	December 7th – Montreal, Quebec

14.3 NPCC Board of Directors Meeting (BOD) 2017

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

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2016 Meeting Dates

February 17th-18th, NextEra Energy Offices, Juno Beach FL
April 19th & 20th, NPCC Offices, New York NY
June 22nd & 23rd, Saratoga NY
August 10th & 11th, Toronto Canada
October 5th & 6th, Lewiston NY
December 8th & 9th, Montreal Canada

RSC 2017 Meeting Date

March 8th-9th, FRCC, Tampa FL
June 7th-8th, Saratoga NY
August 23rd-24th, Toronto/Montreal
October 11th-12th, Lewiston NY
December 7th, General Meeting

15.2 RSC 2016 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 8	January 22	February 5
March 4	March 18	April 1
April 29	May 13	May 27
June 10	July 8	July 22
August 5	September 2	September 16
September 30	October 21	November 4
November 18	December 23	

The meeting is adjourned at 10:32AM on October 6, 2016.

Respectfully Submitted,

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

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

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

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

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

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

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

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

NPCC Representatives on NERC Standards Drafting Teams

Project No.	Project Title	DT Type	NPCC Representatives	Company	Telephone	E-mail Address
2007-06	Phase 1: System Protection Coordination	Standard	None			
2007-06.2	Phase 2: System Protection Coordination	Standard	Ruida Shu Po Bun Ear	NPCC Hydro-Quebec TransEnergie	917-934-7976	rshu@npcc.org ear.po-bun@hydro.qc.c
2007-17.4	PRC-005 FERC Order No. 803 Directive	Standard				
2009-02	Real-time Monitoring and Analysis Capabilities	Standard	T.J. (Tim) Kucey	PSEG Fossil, LLC		Timothy.Kucey@pseg.com
2009-03	Emergency Operations	Standard	Connie Lowe	Dominion Resource Services, Inc.	804-819-2917	connie.lowe@dom.com
2010-05.2	Remedial Action Schemes (Phase 3 of Protection Systems)	Standard	Charles-Eric Langlois	Hydro-Quebec TransEnergie	514-879-4100	langlois.charles-eric@hydro.qc.ca
2010-14.1	Balancing Authority Reliability-Based Control, Phase 1: Reserves	Standard				
2010-14.2	Balancing Authority Reliability-Based Control, Phase 2	Standard				
2010-14.2.2	Periodic Review of BAL Standards - BAL-004	Standard				
2013-03	Geomagnetic Disturbance Mitigation	Standard	Emanuel Bernabeu Kenneth Fleischer Luis Marti	PJM NextEra Energy Hydro One Networks	804-432-8780 561-691-2456 416-345-5317	emanuel.e.bernabeu@dom.com kenneth.fleischer@fpl.com luis.marti@hydroone.com
2014-01	Standards Applicability for Dispersed Generation Resources	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com
2015-03	Periodic Review of System Operating Limit Standards	Standard	Dean Laforest Sam Jager	ISO-NE IESO		
2015-04	Alignment of NERC Glossary of Terms and Definitions Used in the Rules of Procedure (Appendix 2 of the Rules of Procedure)	Standard	Jill Loewer	Utility Services		jill.loewer@utilitysvcs.com
2015-08	Emergency Operations - EOP-004, EOP-005, EOP-006, EOP-008	Standard	Connie Lowe Karen Backmen	Dominion IESO	804-819-2917	connie.lowe@dom.com Karen.backmen@ieso.ca
2015-09	Establish and Communicate System Operating Limits - FAC-010, FAC-011, FAC-014	Standard	Dean Laforest Sam Jager	ISO-NE IESO		
2015-10	Single Points of Failure - TPL-001	Standard	Ovidiu Vasilachi Rich Kowalski	IESO Observer ISO-NE		
2016-01	Modifications to TOP and IRO Standards - TOP-001, IRO-002	Standard	Steve Brain Philippe Labrosse	Dominion Resource Services, Inc. Hydro-Quebec TransEnergie		
2016-03	Cyber Security Supply Chain Management	Standard	Norm Dang David Bryan Gayle	IESO Dominion Resource Services, Inc.		
2016-04	Modifications to PRC-025-1	Standard				

Source = NERC Standard Drafting Team Rosters - September 2016

Projects Added:

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

NPCC Representatives on NERC Standards Drafting Teams						
Project No.	**Project Title**	**DT Type**	**NPCC Representatives**	**Company**	**Telephone**	**E-mail Address**
2007-06	Phase 1: System Protection Coordination	Standard	None			
2007-06.2	Phase 2: System Protection Coordination	Standard	Ruida Shu Po Bun Ear	NPCC Hydro-Quebec TransEnergie	917-934-7976	rshu@npcc.org ear.po-bun@hydro.qc.c
2007-11	Disturbance Monitoring	Standard	Lee Pedowicz	NPCC	212-840-1070	lpedowicz@npcc.org
2007-17.4	PRC-005 FERC Order No. 803 Directive	Standard				
2008-02	Undervoltage Load Shedding	Standard	Charles-Eric Langlois	Hydro-Quebec TransEnergie	514-879-4100	langlois.charles-eric@hydro.qc.ca
2009-02	Real-time Monitoring and Analysis Capabilities	Standard	T.J. (Tim) Kucey	PSEG Fossil, LLC		Timothy.Kucey@pseg.com
2009-03	Emergency Operations	Standard	Connie Lowe	Dominion Resource Services, Inc.	804-819-2917	connie.lowe@dom.com
2010-03	Modeling Data (MOD B)	Standard				
2010-05.1	Protection Systems: Phase 1 (Misoperations)	Standard	Paul Difilippo	Hydro One Networks	647-328-7068	paul.difilippo@hydroone.com
2010-05.2	Remedial Action Schemes (Phase 3 of Protection Systems)	Standard	Charles-Eric Langlois	Hydro-Quebec TransEnergie	514-879-4100	langlois.charles-eric@hydro.qc.ca
2010-13.3	Phase 3 of Relay Loadability: Stable Power Swings	Standard				
2010-14.1	Balancing Authority Reliability-Based Control, Phase 1: Reserves	Standard				
2010-14.2	Balancing Authority Reliability-Based Control, Phase 2	Standard			-	
2010-14.2.2	Periodic Review of BAL Standards - BAL-004	Standard				
2012-09	IRO Five-Year Review	Standard	John Mulhern	Con Edison	212-580 6791	mulhernj@coned.com
2013-03	Geomagnetic Disturbance Mitigation	Standard	Emanuel Bernabeu	Dominion	804-432-8780	emanuel.e.bernabeu@dom.com
			Kenneth Fleischer	NextEra Energy	561-691-2456	kenneth.fleischer@fpl.com
			Luis Marti	Hydro One Networks	416-345-5317	luis.marti@hydroone.com
2013-04	Voltage and Reactive Control (VAR)	Standard	Sharma Kolluri	Entergy	504-576-4045	vkollur@entergy.com
2014-01	Standards Applicability for Dispersed Generation Resources	Standard	Brian Evans-Mongeon	Utility Services	802-241-1400	brian.evans-mongeon@utilitysvcs.com
2014-02	Critical Infrastructure Protection Standards Version 5 Revisions	Standard	Greg Goodrich	NYISO	518-356-7591	ggoodrich@nyiso.com
2014-03	Revisions to TOP/IRO Reliability Standards	Standard				
2014-04	Physical Security	Standard	Kathy Judge	National Grid	508-860-6040	kathleen.judge@nationalgrid.com
2015-02	Emergency Operations Periodic Review	Standard	Connie Lowe	Dominion	804-819-2917	connie.lowe@dom.com
2015-03	Periodic Review of System Operating Limit Standards	Standard	Dean Laforest	ISO-NE		
2015-04	Alignment of NERC Glossary of Terms and Definitions Used in the	Standard	Jill Loewer	Utility Services	802-241-1400	jill.loewer@utilitysvcs.com
2015-06	Interconnection Reliability Operations and Coordination - IRO-006-I	Standard				
2015-07	Internal Communications Capabilities - COM-001	Standard				
2015-08	Emergency Operations - EOP-004, EOP-005, EOP-006, EOP-008	Standard	Connie Lowe Karen Backman	Dominion IESO	804-819-2917	Connie.lowe@dom.com
Source = NERC Standard Drafting Team Rosters - June 2015						
Projects Added:						
1. Project 2015-06 Interconnection Reliability Operations and Coordination - IRO-006-East and IRO-009						
2. Project 2015-07 Internal Communications Capabilities - COM-001						
3. Project 2015-08 Emergency Operations - EOP-004, EOP-005, EOP-006, EOP-008						

NPCC Regional Reliability Standards Executive Tracking Summary

Revised: **9/4/2015**

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

Line No.	Regional Standard ID	Regional Reliability Standard Title	RSAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NPCC BOD Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
1	BPS-501-NPCC-01	Classification of Bulk Power System Elements (Withdrawn by RSC 8/07/09)	Yes (Thru 2/4/08)	NA	NA	NA	NA	NA	NA	NA	Withdrawn by RSC 8/07/09	Withdrawn
2	PRC-002-NPCC-01	Disturbance Monitoring	Yes (Thru 9/10/08)	Yes (Thru 10/24/09)	Yes (Thru 1/6/10)	Yes (1/6/10)	Yes (1/9/10)	Yes (11/4/10)	Yes (5/31/11)	Yes (10/20/11)	10/24/11 - Approved Standard posted publicly	Completed
3	PRC-002-NPCC_02											
4	PRC-006-NPCC-01	Automatic Underfrequency Load Shedding Program	Yes (Thru 8/25/08)	Yes (Thru 11/2/11)	Yes (Pre-ballot Thru 11/2/11)	Yes (11/18/11)	Yes (11/30/11)	Yes (2/9/12)	Yes (5/4/12)	Yes (2/21/13)		Completed
4	PRC-006-NPCC-02	Automatic Underfrequency Load Shedding										Under Development
6	PRC-002-NPCC-02	Disturbance Monitoring	Yes (Thru 2/23/2015)								Regional Standard Authorization Request (RSAR) has been submitted and approved Drafting Team Nomination period ended April 10, 2015	Under Development
7	PRC-002-NPCC-01, Interpretation R1.1		x	x	x	Yes (TFSP 10/19/12)	N/A	N/A	N/A	N/A	Posted on the NPCC website under "Regional Standards General" on 6/24/13	Completed
8	PRC-002-NPCC-01, Interpretation R1.2.2		x	x	x	Yes (TFSP 4/8/13)	N/A	N/A	N/A	N/A	Posted on the NPCC website under "Regional Standards General" on 6/24/13	Completed
7	PRC-002-NPCC-01, Interpretation R4, R5, and R6		x	x	x	Yes (TFSP 5/16/13)	N/A	N/A	N/A	N/A	Posted on the NPCC website under "Regional Standards General" on 6/24/13	Completed
10	BAL-002-NPCC-01	Regional Reserve Sharing	Yes (Thru 11/2/10)	Yes (Thru 12/16/11)	Yes (Thru 1/6/10)						Nomination Form posted - nominations due by 11/10/11	Under Development
11	PRC-012-NPCC-01	Special Protection Systems	Yes (thru 8/18/08)									On Hold
12	Regional Standard Processes Manual	Regional Standard Processes Manual (RSPM)	N/A	Yes (Thru 10/20/13)	Yes (Thru 1/27/14)	Yes (1/27/14)	Yes (3/11/14)				NERC posted the proposed NPCC Regional Standard Processes Manual for a 45-day industry review through 8 p.m. Eastern on Wednesday, May 7, 2014	

x

Acronyms:

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

NPCC Document Open Process Executive Tracking Summary

Revised: **11/9/2016** Further details regarding the individual documents may be found at: https://www.npcc.org/Standards/SitePages/NonStandardsList.aspx

Line No.	Type	Document	Description	Latest Revision	Comments	Status
1	Criteria	A-01	Criteria for Review and Approval of Documents	Mar-05	TFCP Posted for Comment. Comment Period Ends 8/12/2016.	TFCP Reviewing in Accordance with NRAP. TFCP Currently Considering Comments and Potential Revisions in Advance of a 2nd Posting.
2	Criteria	A-10	Classification of BPS Elements	Dec-09	TFCP to Review in 2016.	TFCP Developing Scope of Review---CP11 Review to Begin Early 2017.
3	Criteria	A-15	Disturbance Monitoring Equipment Criteria	Aug-07	A-15 Retired October 2016.	A-15 Retired October 2016 (Directory#11 Approved).
4	Guideline	B-01	NPCC Guide for the Application of Autoreclosing to the Bulk Power System	Feb-13		
5	Guideline	B-12	Guidelines for On Line Computer System Performance During Disturbances	Nov-07		
6	Guideline	B-25	Guide to Time Synchronization Substation Equipment	Nov-08	B-25 Retired October 2016.	Incorporated into Draft Directory#11 (Appendix A)
7	Guideline	B-26	Guide for Application of Disturbance Recording Equipement	Sep-06	B-26 Retired October 2016.	Incorporated into Draft Directory#11 (Appendix B)
8	Guideline	B-27	Regional Critical Asset Identification Methodology	Feb-08	TFIST Retirement Recommendation.	B-27 Retired 6/01/2016.
9	Guideline	B-28	Guide for Generator Sequence of Events Monitoring	Feb-12	B-27 Retired October 2016.	Incorporated into Draft Directory#11 (Appendix C)
10	Procedure	C-01	NPCC Emergency Preparedness Conference Call Procedures - NPCC Security Conference Call Procedures	Jun-16		TFCO Completed Update June 2016.
11	Procedure	C-15	Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems	Jun-16		TFCO Completed Update June 2016.
12	Procedure	C-25	Procedure to Collect Power System Event Data	Sep-07		TFSS to Review and Update for Inclusion in D#11 as Appendix or Recommend Retirement.
13	Procedure	C-29	Procedures for System Modeling:Data Requirements and Facility Ratings	Mar-07	TFSS Retirement Recommendation. (MOD-031-1).	TFSS Retirement Recommendation Currently Posted to the Open Process.
14	Procedure	C-30	Procedure for Task Force on System Protection Review of Disturbances and Protection Misoperations	Dec-09	C-30 Retired June 2016.	
15	Procedure	C-33	Procedure for Analysis and Classification of Dynamic Control Systems	Apr-06		
16	Procedure	C-35	NPCC Power System Restoration Guideline	Mar-16		CO11 Currently Reviewing.
17	Procedure	C-39	Procedure to Collect Major Disturbance Event Data	Dec-09	C-39 Retired June 2016.	
18	Procedure	C-43	NPCC Operational Review for the Integration of New facilities	Aug-08		
19	Procedure	C-45	Procedure for Analysis and Reporting of Protection System Misoperations	Nov-14	TFSP Approved Revised C-45 July, 2016.	

NPCC Directory Executive Tracking Summary

Revised: 11/9/2016 Further details regarding the individual documents may be found at:

	Document	Developed From	Title of Directory	Responsible Task Force	Latest Version	Comments	Status
1	Directory #1	Criteria A-2	Design and Operation of the Bulk Power System	TFCP	Oct-15		
2	Directory #2	Criteria A-3	Emergency Operations	TFCO	Jun-09		TFCO Working Group CO-8 Considering Recommendations/Redlines from CO8 Members Prior to Addressing Review.
3	Directory #3	Criteria A-4	Maintenance Criteria for Bulk Power System Protection	TFSP	Jun-09		Directory#3 Retired Effective April 1st, 2015 Coinciding with the Enforcement Date of PRC -005-2.
4	Directory #4	Criteria A-5	Bulk Power System Protection Criteria	TFSP	Oct-15		
5	Directory #5	Criteria A-6	Reserve	TFCO	Oct-12		
6	Directory #6		Regional Reserve Sharing		Apr-12		
	Directory #7	Criteria A-11	Special Protection Systems	TFSP	Jul-13		Pending Approval of PRC-012-2 TFSP to Consider Review of Directory#7 Criteria and NPCC Glossary Definition of SPS.
	Directory #8	Criteria A-12	System Restoration	TFCO	Oct-10		Subsequent to PRC-005-2 Approval TFCO Has Revised Battery Testing Criteria. CO11 Considered Comments and Will Repost.
	Directory #9	Criteria A-13	Verification of Generator Gross and Net Real Power Capability	TFCO	Dec-11		TFCO Posted Recommendation to Retire D#9 and D#10 Pending Enforcement of MOD-25-2. Comment Period Concluded on 7/30. TFCO to Consider Comments.
	Directory #10	Criteria A-14	Verification of Generator Gross and Net Reactive Power Capability	TFCO	Dec-11		See D#9.
	Directory#11	Criteria A-15	Disturbance Monitoring	TFSP	Oct-16	D#11 Approved October 2016.	
	Directory#12		UFLS	TFSS	Oct-12		

NPCC Directory Criteria Clarifications

Revised: **9/29/2016** 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 on October 16th, 2014.	Yes	Interpretation on behalf of IESO-MACD	Complete.
7	Directory#8 Clarification	System Restoration	12/1/2015	TFCO	Yes on June 6th, 2015.	Yes	Clarification on Behalf of OPG.	Complete.
8	Directory#5 Clarification	Reserve	9/7/2016	TFCO	Posting Completed July 28th, 2016	Yes	Clarification on Behalf of the NYISO.	Complete

11/9/2016

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

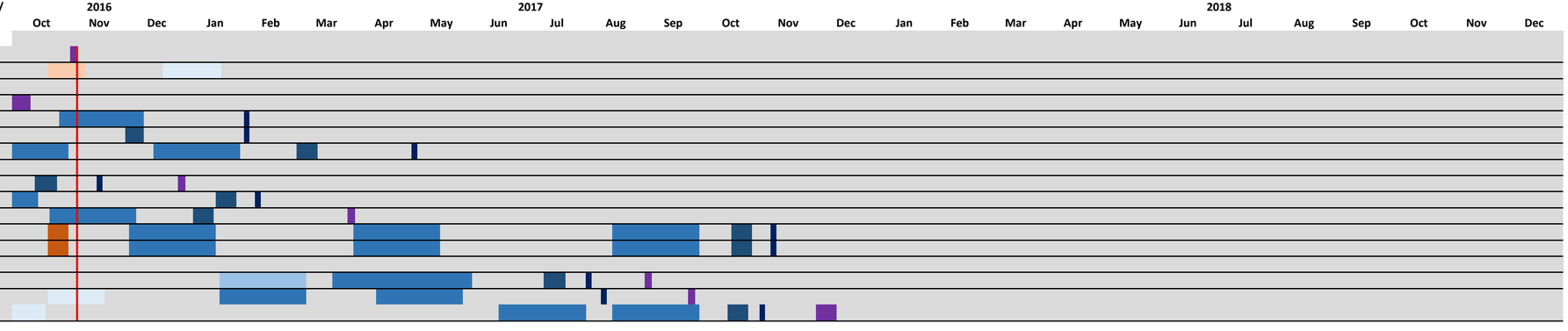
SUMMARY
Tutorial Video (11 min)
Click here to report technical issues

Updated: 11/4/2016

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

HOME

L	Project (Filter)	Deliverables (Filter)	Early/(Late) Days (Filter)	Baseline/ Current (Filter)
F	2010-14.2.2 - Phase 2 of Balancing Authority R	BAL-004	(7)	Current
F	2013-03 - Geomagnetic Disturbance Mitigatio	TPL-007-1		Planning
F	2015-04 - Alignment of Terms	Report on process (Phase II Im		Planning
F	2015-07 - Internal Communications Capabilitie	COM-001-3	(74)	Current
F	2015-08 - Emergency Operations	EOP-005, EOP-006, and EOP-0	(148)	Current
C	2015-08 - Emergency Operations	EOP-004	(100)	Current
F	2015-09 - Establish and Communicate System	FAC-010-3, FAC-011-3, and FA	(58)	Current
C	2015-10 - Single Points of Failure TPL-001	TPL-001		Current
C	2015-INT-01 - Interpretation of CIP-002-5.1 fo	Interpretation CIP-002-5.1	(9)	Current
F	2016-01 - Modifications to TOP and IRO Stand	TOP/IRO Standards		Current
F	2016-02 - Modifications to CIP Standards	LERC Definition		Current
F	2016-02 - Modifications to CIP Standards	Directives, Control Center Con		Current
F	2016-02 - Modifications to CIP Standards	V5TAG, CA and BCA Definition		Current
F	2016-EPR-01 - Enhanced Periodic Review of Pe	PER Stds.		Planning
C	2016-EPR-02 - Enhanced Periodic Review of Ve	VAR-001-4.1 & VAR-002-4		Planning
C	2016-03 - Cyber Security Supply Chain Manage	New and revised Standard(s)		Planning
C	2016-04 - Modifications to PRC-025-1	PRC-025-2		Planning



SUMMARY	(Sorting okay)													HOME
Project	**Project Name**	**Status**	**Comments**	**Deliverable**	**Deadline**	**Priority in 2016-2018 RSDP, if applicable (see Note 1)**	**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**
2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls - BAL-004-2	Pending Board Adoption	Filing anticipated in late November or December	BAL-004	N/A	N/A	N/A	N/A	4	N/A	Darrel Richardson	Ken Goldsmith	BAL-004	10/4/2016
2013-03	Geomagnetic Disturbance Mitigation	Nominations & SAR	FERC issued Order No. 830 on September 22, 2016 approving TPL-007-1 and directing modifications. The SDT will develop revised or new requirements to enhance the benchmark GMD event used in GMD assessments, require collection of GMD data, and establish deadlines for GMD Corrective Action Plans and mitigation measures. Revisions must be filed by May 29, 2018. Projected: Additional SDT noms Oct 20 - Nov 9, 2016; SAR posting Dec 20, 2016 - Jan 13, 2017.	TPL-007-1	43249	N/A	N/A	N/A	N/A	N/A	Mark Olson	Jennifer Sterling	TPL-007-1	10/4/2016
2015-04	Alignment of Terms	Other	SDT is developing recommendations to present to SC. The Phase II work was completed in February 2016 and the proposed recommendations were submitted for consideration at the March 2016 meeting. The item was pulled from the SC agenda based on a request from the SC chair, Brian Murphy. The SDT reviewed the revisions proposed by the SC chair, and determined to move forward with submitting the recommendations as developed by the SDT. The Phase II recommendation document will be resubmitted for inclusion on the September 2016 SC agenda.	Report on process (Phase II Improvement Report)	N/A	N/A	N/A	N/A	N/A	N/A	Lacey Ourso	Andrew Gallo	Glossary/ROP	10/4/2016
2015-07	Internal Communications Capabilities	Pending Regulatory Filing	Filing anticipated in late August.	COM-001-3	N/A	HIGH	N/A	1	N/A	N/A	Darrel Richardson	Brenda Hampton	COM-001-3	10/4/2016
2015-08	Emergency Operations	Posted	Posted for a 45-day additional comment period and ballot.	EOP-005, EOP-006, and EOP-008	N/A	Medium	N/A	1	N/A	N/A	Laura Anderson	Ken Goldsmith	EOP-005, EOP-006, and EOP-008	10/4/2016
2015-08	Emergency Operations	Between Postings	Planning to post for final ballot in late November 2016.	EOP-004	N/A	Medium	N/A	1	N/A	N/A	Laura Anderson	Ken Goldsmith	EOP-004	11/10/2016
2015-09	Establish and Communicate System Operating Limits	Working to Initial Ballot	Proposed revisions to FAC-11-3 and FAC-014-2 were posted for a 30-day informal comment period, from July 14 through August 12. The SDT is scheduled to meet August 23-25 to review the comments and continue drafting revisions to the FAC standards. If the team is able to finalize their proposed revisions at the upcoming meeting, then the revisions will be submitted for authorization to post at the September 14 Standards Committee meeting. However, it will all depend on the nature and volume of comments received through the comment period. More than likely, the SDT will need more time to finalize the draft standards, so I would anticipate us going to the SC for authorization to post at the October or November meeting.	FAC-010-3, FAC-011-3, and FAC-014-2	N/A	Medium	N/A	N/A	N/A	N/A	Lacey Ourso	Andrew Gallo	FAC-010-3, FAC-011-3, and FAC-014-2	10/4/2016
2015-10	Single Points of Failure TPL-001	Working to Initial Ballot	The SDT will meet December 6-8, 2016 in Atlanta, GA to start their initial review of the project scope and determine the correct path forward for each item. The SAR includes: Single points of failure recommendation report by SPCS and SAMS, two outstanding FERC Directives from Order 786 (p. 40 and 89), updating the retired MOD standards stated in TPL-001-4 Requirement R1 will be updated with the current MOD standard. A projected schedule has not been set by the SDT.	TPL-001	N/A	High	N/A	N/A	N/A	N/A	Jordan Mallory	Mark Pratt	TPL-001	11/10/2016
2015-INT-01	Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	Pending Board Adoption	Interpretation passed.	Interpretation CIP-002-5.1	N/A	N/A	N/A	N/A	N/A	N/A	Al McMeekin	Brian Murphy and Andrew Gallo	CIP-002-5.1	11/10/2016
2016-01	Modifications to TOP and IRO Standards	Posted	Posted for second comment and ballot. NOPR issued June 18, 2015 (under previous project 2014-03). Final Rule issued November 19, 2015 with three directives with an associated 18 month regulatory filing deadline. The SC authorized posting at the June 2016 SC meeting. SDT is considering stakeholder comments and revising proposed standards.	TOP/IRO Standards	FERC deadline of July 27, 2017	N/A	N/A	N/A	N/A	N/A	Mark Olson	Rod Kinard	TOP/IRO Standards	10/4/2016
2016-02	Modifications to CIP Standards	Posted	Currently in an additional comment and ballot period.	LERC Definition	Directive: March 31, 2017 (LERC only) (March 31 in SAR)	High	N/A	1	N/A	N/A	Al McMeekin	Brian Murphy and Andrew Gallo	CIP Standards	10/4/2016
2016-EPR-01	Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards	Standing Review Team	Project is on hold until the SC Standing Review Team completes their grading and 30 day posting. Project expected to kick-off in September 2016.	PER Stds.	N/A	N/A	N/A	N/A	N/A	N/A	Darrel Richardson	Mike Brytowski	PER Stds.	10/4/2016

2016-EPR-02	Enhanced Periodic Review of Voltage and Reactive Standards	Working to Comment Posting	The team met with a representative from the Standards Committee (SC) Standing Review Team (SRT) to receive input and feedback from the grading process. The team completed their review the week of October 24, 2016 and are developing recommendations to go to the SRT, perhaps as early as December. When a posting occurs, it will be for a 45-day formal posting. The team has scheduled three conference calls (November 22, December 6 and 8 all at 2:00 p.m. ET). Tentatively, the has penciled in an in-person meeting the week of January 23, 2017, if work continues through the 2016 holiday season.	VAR-001-4.1 & VAR-002-4	N/A	N/A	N/A	N/A	N/A	N/A	Scott Barfield-McGinnis	Amy Casuscelli	VAR-001-4.1 & VAR-002-4	11/10/2016
2016-03	Cyber Security Supply Chain Management	Posted	The project will address directives from Federal Energy Regulatory Commission (FERC) Order No. 829 to develop a new or modified standard to address “supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations.” See Order No. 829, at P1. Projected initial posting Jan 19 - March 6, 2017. "Planned (internal)" 2nd posting (T) April 12 - May 26, 2017.	New and revised Standard(s)	43005	N/A	N/A	1	N/A	N/A	Mark Olson	Brenda Hampton	New and revised Standard(s)	11/10/2016
2016-04	Modifications to PRC-025-1	SAR	The Standards Authorization Request (SAR) was posted for a 30-day formal comment period. Vetted and recommended candidates from the nominations for a SAR drafting team (DT) will go forward for appointments at the Standards Committee (SC) meeting in December. The SAR DT meetings are anticipated to be conference calls due to the few comments received in the SAR posting period. Tentatively, calls would occur after the SC December meeting and the first week January 2017.	New and revised Standard(s)	None, enhancemens to 025 affects entities currently implementing version 1 under the five and seven year implementation period. The first period ends October 1, 2019 and the second on October 1, 2021. Project must consider the time for development and subsequent regulatory	N/A	N/A	N/A	N/A	Yes	Scott Barfield-McGinnis	Charles Yeung	PRC-025-1	11/10/2016

Project	**2010-14.2.2**
Project Name	Phase 2 of Balancing Authority Reliability-based Controls - BAL-004-2
Status	Pending Board Adoption
Comments	Filing anticipated in late November or December
Deliverable	BAL-004
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	4
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Darrel Richardson
PMOS Liaison	Ken Goldsmith
Affected Standards	BAL-004
Last Updated	10/4/2016

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	3/17/2015	4/15/2015	1/15/2015	2/14/2015	(61)		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	8/12/2015	8/25/2015	4/1/2015	5/1/2015	(133)		
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/24/2015	11/12/2015	10/1/2015	11/15/2015	7		
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

FB - Final Ballot	12/8/2015	12/17/2015	12/1/2015	12/11/2015	(7)		
PTB - Present to BOT	2/10/2016	2/12/2016	5/1/2016	5/3/2016	81		
Filing - Filing with Regulators	11/1/2016	11/4/2016	6/1/2016	6/11/2016	(153)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes

Project	**2013-03**
Project Name	Geomagnetic Disturbance Mitigation
Status	Nominations & SAR
Comments	FERC issued Order No. 830 on September 22, 2016 approving TPL-007-1 and directing modifications. The SDT will develop revised or new requirements to enhance the benchmark GMD event used in GMD assessments, require collection of GMD data, and establish deadlines for GMD Corrective Action Plans and mitigation measures. Revisions must be filed by May 29, 2018. Projected: Additional SDT noms Oct 20 - Nov 9, 2016; SAR posting Dec 20, 2016 - Jan 13, 2017.
Deliverable	TPL-007-1
Deadline	May 29, 2018
Priority in 2016-2018 RSDP, if applicable (see Note 1)	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	Mark Olson
PMOS Liaison	Jennifer Sterling
Affected Standards	TPL-007-1
Last Updated	10/4/2016

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR	10/20/2016	11/9/2016	10/20/2016	11/9/2016			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	12/20/2016	1/19/2017	12/20/2016	1/19/2017			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							

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

PTS Change Control

Reason for Update	Date	Notes
No dates provided	6/1/2016	Project finished prior to 2015.

Project	**2015-04**
Project Name	Alignment of Terms
Status	Other
Comments	SDT is developing recommendations to present to SC. The Phase II work was completed in February 2016 and the proposed recommendations were submitted for consideration at the March 2016 meeting. The item was pulled from the SC agenda based on a request from the SC chair, Brian Murphy. The SDT reviewed the revisions proposed by the SC chair, and determined to move forward with submitting the recommendations as developed by the SDT. The Phase II recommendation document will be resubmitted for inclusion on the September 2016 SC agenda.
Deliverable	Report on process (Phase II Improvement Report)
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	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	Lacey Ourso
PMOS Liaison	Andrew Gallo
Affected Standards	Glossary/ROP
Last Updated	10/4/2016

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

Project	**2015-07**
Project Name	Internal Communications Capabilities
Status	Pending Regulatory Filing
Comments	Filing anticipated in late August.
Deliverable	COM-001-3
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	HIGH
P81 Req (2013)	N/A
Number of Directives	1
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Darrel Richardson
PMOS Liaison	Brenda Hampton
Affected Standards	COM-001-3
Last Updated	10/4/2016

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT	6/11/2015	6/24/2015	6/1/2015	6/15/2015	(10)		
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/11/2015	7/11/2015	6/1/2015	7/1/2015	(10)		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/25/2015	11/16/2015	7/15/2015	8/29/2015	(72)		
CAB - Com/Add Ballot 2	3/23/2016	5/9/2016	10/1/2015	11/15/2015	(174)		
CAB - Com/Add Ballot 3			1/1/2016	2/15/2016		Not needed	
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

FB - Final Ballot	6/14/2016	6/24/2016	4/1/2016	4/11/2016	(74)		83.25%
PTB - Present to BOT	8/10/2016	8/12/2016	5/6/2016	5/8/2016	(96)		
Filing - Filing with Regulators	8/10/2016	8/12/2016	8/10/2016	8/12/2016			
PT - Post Approval Training	9/10/2016	10/10/2016	9/10/2016	10/10/2016			

PTS Change Control

Reason for Update	Date	Notes
Update to SC	6/15/2016	Update given to SC concerning delay.

Project	**2015-08**
Project Name	Emergency Operations
Status	Posted
Comments	Posted for a 45-day additional comment period and ballot.
Deliverable	EOP-005, EOP-006, and EOP-008
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	Medium
P81 Req (2013)	N/A
Number of Directives	1
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Laura Anderson
PMOS Liaison	Ken Goldsmith
Affected Standards	EOP-005, EOP-006, and EOP-008
Last Updated	10/4/2016

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review			1/11/2016	1/21/2016			
SP1 - SAR/PR/WP Posting 1	7/21/2015	8/19/2015	7/15/2015	8/14/2015	(6)		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	6/29/2016	8/12/2016	1/25/2016	3/10/2016	(156)		
CAB - Com/Add Ballot 2	***10/26/2016***	***12/9/2016***	***4/4/2016***	***5/19/2016***	(205)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

FB - Final Ballot	11/1/2016	11/11/2016	6/6/2016	6/16/2016	(148)		
PTB - Present to BOT	2/1/2017	2/3/2017	8/8/2016	8/10/2016	(177)		
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Explain delay	6/6/2016	The SDT slowed development.

Project	**2015-08**
Project Name	Emergency Operations
Status	Between Postings
Comments	Planning to post for final ballot in late November 2016.
Deliverable	EOP-004
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	Medium
P81 Req (2013)	N/A
Number of Directives	1
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Laura Anderson
PMOS Liaison	Ken Goldsmith
Affected Standards	EOP-004
Last Updated	11/10/2016

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review			1/11/2016	1/21/2016			
SP1 - SAR/PR/WP Posting 1	7/21/2015	8/19/2015	7/15/2015	8/14/2015	(6)		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	7/25/2016	9/8/2016	4/18/2016	6/2/2016	(98)		
CAB - Com/Add Ballot 2			6/27/2016	8/11/2016			
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

FB - Final Ballot	11/30/2016	12/9/2016	8/22/2016	9/1/2016	(100)		
PTB - Present to BOT	2/1/2017	2/3/2017	10/31/2016	11/2/2016	(93)		
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Explain delay in project	5/1/2016	The delay was to reduce industry burden by simplifying the event reporting process such that a single form and submission system satisfies both EOP-004 and the U.S. Department of Energy's reporting requirements, the Project 2015-08 EOP SDT is collaborating with the U.S. Department of Energy to harmonize reporting requirements/reports. This collaboration has changed the project schedule for EOP-004. The project's PMOS representative, Ken Goldsmith, supports this project timeline change.

Project	**2015-09**
Project Name	Establish and Communicate System Operating Limits
Status	Working to Initial Ballot
Comments	Proposed revisions to FAC-11-3 and FAC-014-2 were posted for a 30-day informal comment period, from July 14 through August 12. The SDT is scheduled to meet August 23-25 to review the comments and continue drafting revisions to the FAC standards. If the team is able to finalize their proposed revisions at the upcoming meeting, then the revisions will be submitted for authorization to post at the September 14 Standards Committee meeting. However, it will all depend on the nature and volume of comments received through the comment period. More than likely, the SDT will need more time to finalize the draft standards, so I would anticipate us going to the SC for authorization to post at the October or November meeting.
Deliverable	FAC-010-3, FAC-011-3, and FAC-014-2
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	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	Lacey Ourso
PMOS Liaison	Andrew Gallo
Affected Standards	FAC-010-3, FAC-011-3, and FAC-014-2
Last Updated	10/4/2016

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

CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/15/2016	10/30/2016	4/18/2016	6/2/2016	(150)		
CAB - Com/Add Ballot 2	12/15/2016	1/29/2017	7/18/2016	9/1/2016	(150)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	3/1/2017	3/11/2017	1/2/2017	1/12/2017	(58)		
PTB - Present to BOT	5/1/2017	5/3/2017	2/1/2017	2/3/2017	(89)		
Filing - Filing with Regulators							
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.
Up coming action	9/14/2016	Schedule baseline correction to address problem noted above.

Project	**2015-10**
Project Name	Single Points of Failure TPL-001
Status	Working to Initial Ballot
Comments	The SDT will meet December 6-8, 2016 in Atlanta, GA to start their initial review of the project scope and determine the correct path forward for each item. The SAR includes: Single points of failure recommendation report by SPCS and SAMS, two outstanding FERC Directives from Order 786 (p. 40 and 89), updating the retired MOD standards stated in TPL-001-4 Requirement R1 will be updated with the current MOD standard. A projected schedule has not been set by the SDT.
Deliverable	TPL-001
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	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	Mark Pratt
Affected Standards	TPL-001
Last Updated	11/10/2016

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR	11/12/2015	12/1/2015	1/18/2016	2/1/2016	67		
Nominations - DT	7/22/2016	8/5/2016	7/25/2016	8/8/2016	3		
QR - Quality Review			5/30/2016	6/9/2016			
SP1 - SAR/PR/WP Posting 1	11/12/2015	12/17/2015	11/12/2015	12/17/2015			
SP2 - SAR/PR/WP Posting 2	5/26/2016	6/24/2016	6/15/2016	7/15/2016	20	Expanded Scope	
CP1 - Comment Period 1							

CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
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
Expansion of Scope	6/14/2016	FERC directives added additional scoping in addition to industry comments following the second SAR posting. The MOD references are being updated due to some retiring in July 2016.

Project	**2015-INT-01**
Project Name	Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)
Status	Pending Board Adoption
Comments	Interpretation passed.
Deliverable	Interpretation CIP-002-5.1
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	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	Al McMeekin
PMOS Liaison	Brian Murphy and Andrew Gallo
Affected Standards	CIP-002-5.1
Last Updated	11/10/2016

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT			4/15/2016	4/29/2016			
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)	7/27/2016	9/12/2016	7/25/2016	9/8/2016	(2)		
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							

CAB - Com/Add Ballot 5							
FB - Final Ballot	10/13/2016	10/24/2016	10/4/2016	10/14/2016	(9)		91.31%
PTB - Present to BOT	***11/15/2016***	***11/17/2016***	11/15/2016	11/17/2016			
Filing - Filing with Regulators	12/28/2016	12/31/2016	12/28/2016	12/31/2016			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Transfer RFI to the CIP SDT and update the SC	6/14/2016	Schedule updated to CIP SDT timeline.
Add CIP Schedule for approval	7/20/2016	Update SC that schedule was approved by SDT, SDT leadership, developer, and PMOS Liaison.

Project	**2016-01**
Project Name	Modifications to TOP and IRO Standards
Status	Posted
Comments	Posted for second comment and ballot. NOPR issued June 18, 2015 (under previous project 2014-03). Final Rule issued November 19, 2015 with three directives with an associated 18 month regulatory filing deadline. The SC authorized posting at the June 2016 SC meeting. SDT is considering stakeholder comments and revising proposed standards.
Deliverable	TOP/IRO Standards
Deadline	FERC deadline of July 27, 2017
Priority in 2016-2018 RSDP, if applicable (see Note 1)	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	Mark Olson
PMOS Liaison	Rod Kinard
Affected Standards	TOP/IRO Standards
Last Updated	10/4/2016

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT	1/22/2016	2/4/2016	4/18/2016	5/2/2016	87		
QR - Quality Review	5/10/2016	5/23/2016	6/27/2016	7/7/2016	48		
SP1 - SAR/PR/WP Posting 1	1/22/2016	2/22/2016	3/7/2016	4/6/2016	45		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							

CIB - Com/Ballot 1 (Initial)	6/20/2016	8/3/2016	7/11/2016	8/25/2016	21		IRO-002-5 (67.25%) TOP-001-4 (64.59%)
CAB - Com/Add Ballot 2	8/31/2016	10/14/2016	10/24/2016	12/8/2016	54		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/17/2017	1/27/2017	1/17/2017	1/27/2017			
PTB - Present to BOT	2/7/2017	2/9/2017	2/7/2017	2/9/2017			
Filing - Filing with Regulators	7/24/2016	7/27/2016	7/24/2016	7/27/2016			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Periodic Update	8/21/2016	Developer updated FERC deadline from 5/19/17 to 7/27/17

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	Posted
Comments	Currently in an additional comment and ballot period.
Deliverable	LERC Definition
Deadline	Directive: March 31, 2017 (LERC only) (March 31 in SAR)
Priority in 2016-2018 RSDP, if applicable (see Note 1)	High
P81 Req (2013)	N/A
Number of Directives	1
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Al McMeekin
PMOS Liaison	Brian Murphy and Andrew Gallo
Affected Standards	CIP Standards
Last Updated	10/4/2016

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT	3/10/2016	3/24/2016	3/10/2016	3/24/2016			
QR - Quality Review	6/30/2016	7/6/2016	6/30/2016	7/7/2016			
SP1 - SAR/PR/WP Posting 1	3/23/2016	4/21/2016	3/23/2016	4/21/2016			
SP2 - SAR/PR/WP Posting 2	6/1/2016	6/30/2016	6/1/2016	7/1/2016		Expanded Scope	
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	7/21/2016	9/6/2016	7/25/2016	9/8/2016	4		
CAB - Com/Add Ballot 2	***10/21/2016***	***12/5/2016***	10/17/2016	12/1/2016	(4)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

FB - Final Ballot	1/5/2017	1/15/2017	1/5/2017	1/15/2017			
PTB - Present to BOT							
Filing - Filing with Regulators	3/28/2017	3/31/2017	3/28/2017	3/31/2017			
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. Second SAR posting was required due to expansion of scope.

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	SAR
Comments	Draft rationale/purpose statements, consider requirement structures, Draft requirement language, Take a close look at Measures; To QR - Oct 20; SC Mtg - Nov 17 (Nov 3 SC agenda); (will require scheduling an off-cycle meeting)
Deliverable	Directives, Control Center Comm Nets (CIP-006), TD at Lows (CIP-010 or CIP-003)
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	High
P81 Req (2013)	N/A
Number of Directives	2
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Al McMeekin
PMOS Liaison	Brian Murphy and Andrew Gallo
Affected Standards	CIP Standards
Last Updated	10/4/2016

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review	10/20/2016	10/30/2016	10/20/2016	10/30/2016			
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	12/2/2016	1/16/2017	12/2/2016	1/16/2017			
CAB - Com/Add Ballot 2	3/31/2017	5/15/2017	3/31/2017	5/15/2017			
CAB - Com/Add Ballot 3	8/15/2017	9/29/2017	8/15/2017	9/29/2017			

CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	10/17/2017	10/27/2017	10/17/2017	10/27/2017			
PTB - Present to BOT	11/7/2017	11/9/2017	11/7/2017	11/9/2017			
Filing - Filing with Regulators	12/28/2016	12/31/2016	12/28/2016	12/31/2016			
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

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	SAR
Comments	Draft rationale/purpose statements, consider requirement structures, Draft requirement language, Take a close look at Measures; To QR - Oct 20; SC Mtg - Nov 17 (Nov 3 SC agenda); (will require scheduling an off-cycle meeting)
Deliverable	V5TAG, CA and BCA Definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), TO Control Centers, Virtualization
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	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	Al McMeekin
PMOS	Brian Murphy and Andrew Gallo
Affected Standards	CIP Standards
Affected Standards	10/4/2016

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review	10/20/2016	10/30/2016	10/20/2016	10/30/2016			
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	12/2/2016	1/16/2017	12/2/2016	1/16/2017			
CAB - Com/Add Ballot 2	3/31/2017	5/15/2017	3/31/2017	5/15/2017			

CAB - Com/Add Ballot 3	8/15/2017	9/29/2017	8/15/2017	9/29/2017			
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	10/17/2017	10/27/2017	10/17/2017	10/27/2017			
PTB - Present to BOT	11/7/2017	11/9/2017	11/7/2017	11/9/2017			
Filing - Filing with Regulators	12/28/2016	12/31/2016	12/28/2016	12/31/2016			
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.

Project	**2016-EPR-01**
Project Name	Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards
Status	Standing Review Team
Comments	Project is on hold until the SC Standing Review Team completes their grading and 30 day posting. Project expected to kick-off in September 2016.
Deliverable	PER Stds.
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	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	Darrel Richardson
PMOS Liaison	Mike Brytowski
Affected Standards	PER Stds.
Last Updated	10/4/2016

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

Project	**2016-EPR-02**
Project Name	Enhanced Periodic Review of Voltage and Reactive Standards
Status	Working to Comment Posting
Comments	The team met with a representative from the Standards Committee (SC) Standing Review Team (SRT) to receive input and feedback from the grading process. The team completed their review the week of October 24, 2016 and are developing recommendations to go to the SRT, perhaps as early as December. When a posting occurs, it will be for a 45-day formal posting. The team has scheduled three conference calls (November 22, December 6 and 8 all at 2:00 p.m. ET). Tentatively, the has penciled in an in-person meeting the week of January 23, 2017, if work continues through the 2016 holiday season.
Deliverable	VAR-001-4.1 & VAR-002-4
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	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	Scott Barfield-McGinnis
PMOS Liaison	Amy Casuscelli
Affected Standards	VAR-001-4.1 & VAR-002-4
Last Updated	11/10/2016

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR	2/10/2016	2/23/2016	2/10/2016	2/23/2016			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	1/19/2017	3/5/2017	1/19/2017	3/5/2017			

CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	3/20/2017	5/4/2017	3/20/2017	5/4/2017			
CAB - Com/Add Ballot 2	4/17/2017	6/1/2017	4/17/2017	6/1/2017			
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	7/10/2017	7/20/2017	7/10/2017	7/20/2017			
PTB - Present to BOT	8/1/2017	8/3/2017	8/1/2017	8/3/2017			
Filing - Filing with Regulators	9/1/2017	9/4/2017	9/1/2017	9/4/2017			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes

Project	**2016-03**
Project Name	Cyber Security Supply Chain Management
Status	Posted
Comments	The project will address directives from Federal Energy Regulatory Commission (FERC) Order No. 829 to develop a new or modified standard to address "supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations." See Order No. 829, at P1. Projected initial posting Jan 19 - March 6, 2017. "Planned (internal)" 2nd posting (T) April 12 - May 26, 2017.
Deliverable	New and revised Standard(s)
Deadline	Wednesday, September 27, 2017
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A
P81 Req (2013)	N/A
Number of Directives	1
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Mark Olson
PMOS Liaison	Brenda Hampton
Affected Standards	New and revised Standard(s)
Last Updated	11/10/2016

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT	7/29/2016	8/18/2016	7/29/2016	8/18/2016			
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	***10/20/2016***	***11/18/2016***	***10/20/2016***	***11/21/2016***			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	1/19/2017	3/5/2017			(42754)		

CAB - Com/Add Ballot 2	4/12/2017	5/27/2017			(42837)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT	8/9/2017	8/11/2017	8/9/2017	8/11/2017			
Filing - Filing with Regulators	9/24/2017	9/27/2017	9/24/2017	9/27/2017			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Create project record	8/1/2016	Added project to PTS.
Periodic Update	8/21/2016	Added FERC deadline

Project	**2016-04**	**Home**
Project Name	Modifications to PRC-025-1	
Status	SAR	
Comments	The Standards Authorization Request (SAR) was posted for a 30-day formal comment period. Vetted and recommended candidates from the nominations for a SAR drafting team (DT) will go forward for appointments at the Standards Committee (SC) meeting in December. The SAR DT meetings are anticipated to be conference calls due to the few comments received in the SAR posting period. Tentatively, calls would occur after the SC December meeting and the first week January 2017.	
Deliverable	PRC-025-2	
Deadline	None, enhancemens to 025 affects entities currently implementing version 1 under the five and seven year implementation period. The first period ends October 1, 2019 and the second on October 1, 2021. Project must consider the time for development and subsequent regulatory	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	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)	Yes	
Developer	Scott Barfield-McGinnis	
PMOS Liaison	Charles Yeung	
Affected Standards	PRC-025-1	
Last Updated	11/10/2016	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR	9/16/2016	9/28/2016	9/16/2016	9/28/2016			
Nominations - DT	2/1/2016	2/11/2016	2/1/2016	2/11/2016			
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	9/16/2016	10/18/2016	9/16/2016	10/18/2016			
SP2 - SAR/PR/WP Posting 2							

CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	6/16/2017	7/31/2017	6/16/2017	7/31/2017			
CAB - Com/Add Ballot 2	8/15/2017	9/29/2017	8/15/2017	9/29/2017			
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	10/15/2017	10/25/2017	10/15/2017	10/25/2017			
PTB - Present to BOT	11/1/2017	11/3/2017	11/1/2017	11/3/2017			
Filing - Filing with Regulators	12/1/2017	12/11/2017	12/1/2017	12/11/2017			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
SC Authorized Posting	9/14/2016	SAR and SAR SDT nominations.

No.	Description
Note 1	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	
Note 7	
Note 8	
Note 9	
Note 10	

RSC Meeting #16-6, Agenda Item 4.0 Open Action Items

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

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Weekly Standards & Compliance Bulletin

November 14–20, 2016

ACTIVE STANDARDS POSTINGS

Current and Upcoming Ballots (ballot periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2016-02 – Modifications of CIP Standards | CIP-003-7 and Implementation Plan	Additional Ballots and Non-binding Poll	11/23/16	12/05/16
Project 2015-08 – Emergency Operations | EOP-005-3 and EOP-006-3	Additional Ballots	11/30/16	12/09/16
Join Ballot Pools (ballot pool windows close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
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Posted for Comment (comment periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2016-03 – Cyber Security Supply Chain Management – Standards Authorization Request	Use the electronic form to submit comments on the SAR.	10/20/16	11/18/16
Project 2016-02 – Modifications of CIP Standards | CIP-003-TCA A draft RSAW is posted through December 5, 2016. Submit comments to RSAWfeedback@nerc.net.	Use informal comment form.	11/01/16	11/18/16
Project 2016-02 – Modifications of CIP Standards | CIP-003-7 and Implementation Plan	Use comment form.	10/21/16	12/05/16
Project 2015-08 – Emergency Operations | EOP-005-3 and EOP-006-3 Consideration of Issues and Directives Posted NEW Draft RSAWs are posted through December 9, 2016. Submit comments to RSAWfeedback@nerc.net.	Use comment form.	10/26/16	12/09/16

OTHER ACTIVE COMMENT PERIODS

Posted for Comment			
Posting	**Action**	**Start Date**	**End Date**
Comment Period Open for Version 3.1 of the Draft ERO Event Analysis Process and Appendices: In an effort to continually improve the ERO Event Analysis Process (EAP), the NERC Operating Committee tasked the NERC Event Analysis Subcommittee (EAS) with review of the EAP. In Version 3, the EAS moved to an as needed review period for the EAP. The EAS received a request from Texas Regional Entity to review and revise the event Categories 1g and 3a with respect to the more stringent thresholds placed on the ERCOT Interconnection. The EAS reviewed the thresholds along with the justification for the proposed and concurred with the need to revise the respective Categories. The EAS also revised Category 2a to align with NERC Reliability Standard COM-001-2.1 and the latest draft of EOP-004-4. The Appendices were not revised as there was not an immediate need to make revisions.	Submit comments using the comment form.	09/30/16	11/14/16
Comment Period Open for Integrating Reporting ACE with the NERC Reliability Standards Draft Reliability Guideline: The NERC Operating Committee's Resources Subcommittee and the Phase 2 of the Balancing Authority Reliability-based Controls standard drafting team developed the draft Reliability Guideline: Integrating Reporting Area Control Error (ACE) with the NERC Reliability Standards. This Reliability Guideline is intended to provide recommended practices for calculating and using	Submit comments using the comment form.	09/30/16	11/14/16

Reporting ACE in the Tie Line Bias Control program integrated with the NERC Reliability Standards.			
Comment Period Open for Situational Awareness for the System Operator Draft Reliability Guideline: The NERC Operating Committee's Resources Subcommittee, Operating Reliability Subcommittee and Personnel Subcommittee developed the draft Reliability Guideline: Situational Awareness for the System Operator. This Reliability Guideline provides a global recognition of the importance for the system operator to maintain situational awareness while operating the BES. It is meant to assist Transmission Operators (TOP), Balancing Authorities (BA), Reliability Coordinators (RC), Generator Operators (GOP) and other operating entities to use as they deem appropriate with the primary goal of supporting BES reliability.	Submit comments using the comment form.	09/29/16	11/14/16
Comment Period Open for Inadvertent Interchange Draft Reliability Guideline: The NERC Operating Committee's Resources Subcommittee and the Phase 2 of the Balancing Authority Reliability-based Controls standard drafting team developed the draft Reliability Guideline: Inadvertent Interchange. This Reliability Guideline is intended to provide recommended practices for the management of Inadvertent Interchange accounting. With the goal of ensuring that, over the long term, Balancing Authority (BA) Areas do not excessively depend on the BA Areas in the Interconnection for meeting their demand or Interchange obligations.	Submit comments using the comment form.	09/29/16	11/14/16
Comment Period Open for PRC-006-3 – Automatic Underfrequency Load Shedding NPCC Quebec Regional Variance Revision: This proposed revision to the NPCC Regional Variance specifically applies to the Quebec Region only. Due to the unique nature of the Quebec	Comments may be submitted electronically through the NPCC Website.	11/02/16	12/15/16

province being its own interconnection, the variance is being developed using the NPCC Regional Standard Processes Manual. Specifically, the "Section D. Regional Variance" and "Attachment 1A," which apply only to Quebec, have been revised to reflect the unique nature of the Quebec interconnection.			
NEW **Comment Period Open for Proposed Revisions to the NERC Rules of Procedure:** NERC is proposing revisions to currently effective Sections 600 (Personnel Certification) and 900 (Training and Education) of its Rules of Procedure. The purpose of these revisions is twofold. First, NERC proposes to clarify the scope of the Personnel Certification Program, the Training and Education Program and the Continuing Education Program. Second, NERC proposes to modernize and align the language of the ROP with current practices of those programs. A redlined version of NERC Rules of Procedure, Sections 600 and Section 900 showing the proposed revisions are now available at: NERC Rules of Procedure. NERC intends to submit these changes to the NERC Board of Trustees for consideration at its February 2017 meeting.	Submit comments to ROPcomments@nerc.net.	11/09/16	12/24/16

STANDARDS NEWS

There is nothing additional to report for this week.

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

GENERAL COMPLIANCE AND ENFORCEMENT NEWS

NEW NERC Releases Ten Reliability Standard Audit Worksheets

Ten new Reliability Standard Audit Worksheets (RSAWs) have been posted to the RSAW homepage under the heading 'Current RSAWs for Use.' IRO-001-4, IRO-002-4, IRO-008-2, MOD-029-2a, MOD-030-3, PRC-015-1, PRC-016-1, PRC-017-1, and PRC-023-4 become effective on April 1, 2017. PRC-004-5(i) becomes effective on April 2, 2017.

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

STANDARDS SUBJECT TO FUTURE ENFORCEMENT

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

U.S. Enforcement Date	Standard(s)
January 1, 2017	IRO-010-2 - Reliability Coordinator Data Specification and Collection (Requirements R1 and R2);
	TOP-003-3 – Operational Reliability Data (all Requirements except R5);

April 1, 2017	CIP-003-6 – Cyber Security – Security Management Controls (Requirements 1.2–2); CIP-010-2 – Cyber Security — Configuration Change Management and Vulnerability Assessments (Requirement 4)
	EOP-004-3 – Event Reporting; EOP-010-1 – Geomagnetic Disturbance Operations (Requirement 2); EOP-011-1 – Emergency Operations;
	FAC-010-3 – System Operating Limits Methodology for the Planning Horizon; FAC-011-3 – System Operating Limits Methodology for the Operations Horizon;
	IRO-001-4 – Reliability Coordination: Responsibilities; IRO-002-4 – Reliability Coordination: Monitoring and Analysis; IRO-008-2 – Reliability Coordinator Operational Analyses and Real-time Assessments; IRO-010-2 – Reliability Coordinator Data Specification and Collection (Requirement R3); IRO-014-3 – Coordination Among Reliability Coordinators; IRO-017-1 – Outage Coordination;
	MOD-029-2a – Rated System Path Methodology; MOD-030-3 – Flowgate Methodology;
	PRC-010-1 – Undervoltage Load Shedding; PRC-004-WECC-2 – Protection System and Remedial Action Scheme Misoperation; PRC-015-1 – Remedial Action Scheme Data and Documentation; PRC-016-1 – Remedial Action Scheme Misoperations; PRC-017-1 – Remedial Action Scheme Maintenance and Testing; PRC-023-4 – Transmission Relay Loadability
	TOP-001-3 – Transmission Operations; TOP-002-4 – Operations Planning; TOP-003-3 – Operational Reliability Data (Requirement R5);
April 2, 2017	PRC-004-5(i) – Protection System Misoperation Identification and Correction; PRC-010-2 – Undervoltage Load Shedding;
July 1, 2017	CIP-004-6 – Cyber Security – Personnel & Training (Requirements 2.3, 4.3, 4.4); CIP-006-6 – Cyber Security — Physical Security of BES Cyber Systems (Requirement 3.1); CIP-008-5 – Cyber Security — Incident Reporting and Response Planning (Requirement 2.1);

	CIP-009-6 – Cyber Security — Recovery Plans for BES Cyber Systems (Requirement 2.1–2.2); CIP-010-2 – Cyber Security — Configuration Change Management and Vulnerability Assessments (Requirement 3.1);
	MOD-033-1 – Steady-State and Dynamic System Model Validation;
	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events
October 1, 2017	NEW COM-001-3 – Communications
January 1, 2018	PRC-026-1 – Relay Performance During Stable Power Swings (Requirement 1);
July 1, 2018	CIP-009-6 – Cyber Security — Recovery Plans for BES Cyber Systems (Requirement 2.3); CIP-010-2 – Cyber Security — Configuration Change Management and Vulnerability Assessments (Requirements 3.2, 3.2.1, 3.2.2);
	MOD-026-1 – Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions (Requirements R2, 2.1–2.1.6); MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions (Requirements R2, 2.1–2.1.5);
	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirement 2)
January 1, 2019	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirement 5)
January 1, 2021	PRC-026-1 – Relay Performance During Stable Power Swings (Requirements 2–4)
	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirement 6)
January 1, 2022	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements 3,4,7)

BOARD OF TRUSTEES AND FERC ACTION

NEW NERC Filings

On November 10, 2016, NERC filed with FERC a petition for approval of amendments to the Florida Reliability Coordinating Council Regional Reliability Standard Development Process Manual and a petition for approval for retirement of Reliability Standard BAL-004-0 – Time Error Correction.

On November 9, 2016, NERC filed with FERC a joint petition with the Western Electricity Coordinating Council for approval of interpretation of proposed regional Reliability Standard BAL-002-WECC-2a – Contingency Reserve.

On November 7, 2016, NERC filed a compliance filing for proposed revisions to the Violation Risk Factors for Requirement R1 of Reliability Standard IRO-018-1 – Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities and Requirements R1 and R2 of Reliability Standard TOP-010-1 – Real-time Reliability Monitoring and Analysis Capabilities.

NERC's 2016 filings to FERC are available here.

NEW FERC Issuances

On October 31, 2016, FERC issued an order approving Reliability Standard COM-001-3 – Communications.

On November 4, 2016, FERC issued a letter order accepting NERC's August 15, 2016 filing of proposed revisions to its Rules of Procedure (ROP) to incorporate Frequency Response Sharing Group and Regulation Reserve Sharing Group to the following parts of the NERC ROP: (i) Appendix 2 - Definitions Used in the Rules of Procedure; (ii) Appendix 5A - Organization Registration and Certification Manual; and (iii) Appendix 5B - Statement of Compliance Registry Criteria.

FERC's 2016 issuances 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

- Emerging Technology Roundtable – November 15–16, 2016, Atlanta | Register

Webinars

- NEW Project 2016-02 – Modifications to CIP Standards – 12:30–1:30 p.m. Eastern, November 15, 2016 | Register

- **NEW** Project 2015-08 – Emergency Operations: EOP-004-4, EOP-005-3, EOP-006-3 and EOP-008-2 Webinar – 11:00 a.m.–12:30 p.m. Eastern, November 18, 2016 | Register
- EX2000 and GENTPJ Modeling Notifications Webinar – 2:00–3:00 p.m. Eastern, December 2, 2016 | Register
- Node-Breaker Modeling Representation Webinar – 11:00–3:00 p.m. Eastern, December 6, 2016 | Register
- Dynamic Load Modeling Task Force Webinar – 1:30–3:00 p.m. Eastern, December 9, 2016 | Register

Standing Committee Meetings and Conference Calls

- Operating Committee, Planning Committee, and Critical Infrastructure Protection Committee Meetings – December 13–14, 2016 | Atlanta | Register for OC | Register for PC | Register for CIPC | Register for hotel (before November 25, 2016)

Standard Drafting Team Meetings

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

- Project 2015-09 – System Operating Limits Standard – November 8–10, 2016, Vancouver, WA | Register
- Project 2016-02 – Modifications to CIP Standards – November 15–17, 2016, Portland, OR | Register
- Functional Model Advisory Group – November 18, 2016 | Register with Access Code: 5216143
- Project 2016-03 – Cyber Security Supply Chain Management – November 29–December 1, 2016, Audubon, PA | Register
- Project 2015-10 – Single Points of Failure – December 6–10, 2016, Atlanta, GA | Register

ABOUT THE WEEKLY STANDARDS & COMPLIANCE BULLETIN

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

If you would like to receive this bulletin or be added to the distribution list for a particular standards project, please email sarcomm@nerc.net. For more information about any of the compliance news listed in the bulletin, please contact Linda Jenkins.

From: Guy V. Zito
To: Ruida Shu
Subject: FW: Quebec GMD Studies and presentation
Date: Friday, October 14, 2016 6:08:05 PM
Attachments: image004.png

Ruida,

Let's accommodate the request when the agenda is developed. Don't send out the below. It is confidential at this point, just leave a slot for HQ as mentioned below. Materials for that item number will be out later.

Thanks and Enjoy the weekend. Hope you are feeling better. Get some rest on the weekend.

Guy

From: Phan, Si Truc [mailto:Phan.Si_Truc@hydro.qc.ca]
Sent: Friday, October 14, 2016 4:17 PM
To: Guy V. Zito <gzito@npcc.org>
Subject: Quebec GMD Studies and presentation

Bonjour Guy,
Hopes everything is fine.
For your information only.
We had an internal GMD committee last week.
Team members presented many results of studies. It's going well.
Ready to be presented for our next RSC meeting as per my request. It will be an interesting session.
So many material so is it possible to reserve at least 1 hour for presentation and discussion at the agenda? OK to plan for December 8th at 13:00h or next day?

Here is results:

- Based on data obtained from Ottawa, the 1989 GIC storms occurred during 2 days. 5 strong peaks had been recorded. From EMTP software, simulation show HQ network failed already at the first peak. From simulation, team demonstrated the voltage collapse of the grid at the value of 1V/km, caused by harmonics distortion. No hot spot found on simulation. It's a premier. Team continue to simulate others variances from successive peaks.

- From Hypersim (real time) simulation to the 2016 HQ network, team found than grid still survived at 3 V/km but with a ugly waveform. Network collapsed at 4 V/km. Field was apply uniformly. Team did also with variance of variable V/km. Strongest was observed at 2V/km !?! More to find…

For now, team is preparing to write reports of results found.

Moreover, Homeland Security will meet our experts next week at IREQ with these questions on a higher level. We are preparing some answers. Will send you a copy when ready.

- How has Hydro-Quebec examined—i.e., what research have you conducted—the potential scale of damage that could result from a GMD event?
- What actions Hydro-Quebec has taken since 1989 to prevent a recurrence of the events that transpired as a result of the March 1989 superstorm?
- What, if any, incentives does Hydro-Quebec receive from the federal or provincial governments to encourage you to prepare for or mitigate the impacts of a GMD event?
- We understand that Hydro-Quebec has installed 32 series capacitor banks to its transmission system. What role do these capacitor banks play in preventing the spread of geomagnetically induced current (GIC) during a GMD event? What other steps has Hydro-Quebec taken to mitigate the potential effects of a large-scale GMD?
- What technologies are available to help prevent or mitigate the effects of large-scale GMD events and how effective are they? What are the key factors affecting the development and implementation of these technologies?
- How would Hydro-Quebec react differently to a GMD event now compared to how you reacted to the superstorm in 1989?
- What are your thoughts on the 2012 near miss solar storm and what preparations, if any, did Hydro-Quebec take to prepare for it?

Please keep it confidential.
Thanks

Si Truc PHAN
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November 9th, 2016

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

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

NPCC Reliability Standards Committee Program Responsibilities (related to Standards)

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

1. Monitor NERC's Reliability Issues Steering Committee (RISC) risk profiles and other reliability related issues and priorities for potential incorporation into NERC standards, for removal from standards or for potential incorporation into guidelines or other non-standards solutions. Provide and coordinate NPCC's input into those decisions.
2. Coordinate and provide input to the development and prioritization of ERO reliability standards within the NERC Reliability Standards Development Plan through active regional participation in the Enhanced Periodic Review Standing Committee.
3. Review and support the ERO results-based standards initiative and ongoing standards development work towards the ERO goal of a 'steady-state' of standard development which is defined to be a core set of results-based standards achieving an adequate level of reliability and subject to little change by providing ongoing input to the Enhanced Periodic Review Template used to determine the efficacy of standards.
4. Promote the steady-state standards initiative throughout the Northeast.
5. Continue to provide input to the development of a model for consideration of costs in NERC's Standards Development program. [Cost of Risk Reduction Analysis (CRRA) first draft and pilot.]
6. Oversee, and participate in the regional standards development process and base any development, revision or retirement of NPCC Regional Reliability Standards on the reliability related needs of the Region or continent-wide ERO standards such as:
    a. Revision of NPCC PRC-006-NPCC-01 Underfrequency Load Shedding
    b. Revision of NERC PRC-006-2 Underfrequency Load Shedding (Quebec Regional Variance)
7. Engage in the newly approved NERC Compliance ~~Policy~~ Guidance Policy process~~program~~. Support the inputs through the NPCC Compliance Committee by providing technical and policy related opinions as necessary.
8. Coordinate NPCC Regional Standards development activity with NERC Standards development activity to ensure resources are available for efficient and effective standards development and implementation.

Commented [HS1]: Consider whether in light of item 2 above we really need this item.

Commented [GJD2]: This seems duplicative with item 3.

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

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Commented [HS3]: Do we need this one since we do not anticipate regional standards being developed any time soon?

Commented [GJD4]: Regarding Herb's comment the item is still valid since the potential exists to revise or retire existing regional standards.

input to support development of a NPCC consensus opinion.

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

Commented [HS5]: Perhaps this one should be a separate item?

Commented [HS6]: Perhaps this one should be moved up to HS 1 comment.

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

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

Commented [HS7]: Confirm – is this is a NPCC bylaw section? If so, say it. Otherwise, what is it. Or is it a NPCC member agreement section?

Commented [GJD8]: Added NERC ROP.

Commented [HS9]: Not sure I understand this one. Perhaps we should discuss intention during the meeting.

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.

Clean
November 9, 2016

Scope of Work
for the
Regional Standards Committee (RSC)

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

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

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

The RSC is an open and balanced committee inclusive of all stakeholders that provide for, or are materially impacted by the reliability of the Bulk Electric System. The RSC meetings are open

to all stakeholders who want to participate and meeting materials will be publicly posted on the NPCC Website.

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

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

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

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

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

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

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

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

RSC Members should make every effort to attend scheduled meetings and when not available are required to identify and provide a qualified proxy participant. RSC business cannot be conducted in the absence of a quorum and it is essential that each RSC 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 standards process for the development of ERO Regional Standards, Violation Risk Factors (VRFs), Violation Severity Levels (VSLs), definitions, variances, interpretations and clarifications in accordance with the NPCC Regional Standard Processes Manual and the NPCC Amended and Restated Bylaws pertaining to quorum and voting rules. The RSC is responsible for ensuring the quality of all Standards-related materials.

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

~~All RSC Regional Standard-related decision-making activities will be approved or rejected by a vote as outlined in the NPCC Amended and Restated Bylaws as they pertain to quorum and voting rules.~~

B. NPCC Directory and Criteria Process Responsibilities

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

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

C. NERC Reliability Standards Responsibilities

The RSC will:

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

provide NPCC members with basic information (or assistance with the NERC Website) for a common understanding of the process.

- Coordinate the activities of NPCC members on Standard Drafting Teams, and encourage NPCC representation on all Standard Drafting Teams.
- Coordinate with the CC any NPCC input to the ERO Compliance Guidance Policy in accordance with the CMEP Implementation Guidance Process.

D. FERC Activities Affecting Standards

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

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation

Standard Drafting Team Nomination Period Open through November 9, 2016

Now Available

Nominations are being solicited for additional standard drafting team (SDT) members through **8 p.m. Eastern, Wednesday, November 9, 2016**.

The SDT will develop the following revisions to Reliability Standards in response to FERC Order No. 830:

- Modify the benchmark GMD event definition used for GMD Vulnerability Assessments;
- Make related modifications to requirements pertaining to transformer thermal impact assessments;
- Require entities to collect GMD-related data. NERC is directed to make data available; and
- Require deadlines for Corrective Action Plans (CAPs) and GMD mitigating actions.

FERC established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which is May 2018.

SDT nominations are solicited to maintain a well-qualified and diverse team capable of revising TPL-007-1 to address FERC Order No. 830 directives. Nominees should have transmission planning experience and understanding of GMD studies and mitigation strategies.

Use the electronic form to submit a nomination. If you experience any difficulties using the electronic form, contact Nasheema Santos. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

A significant time commitment is expected of SDT members to meet the 18-month regulatory deadline established in Order No. 830. SDT activities include participation in technical conferences, stakeholder communications and outreach events, periodic drafting team meetings and conference calls. Approximately two in-person meetings per quarter can be expected (on average three full working days each meeting), as well as periodic conference calls as needed.

Previous SDT experience is beneficial but not required. See the nomination form for additional information.

Next Steps
The Standards Committee is expected to appoint members to the SDT in December 2016. Nominees will be notified shortly after they have been appointed**.**

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email) or at (404) 446-9760.

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Benchmark Geomagnetic Disturbance Event Description

Project 2013-03 GMD Mitigation
Standard Drafting Team
May 12, 2016

RELIABILITY | ACCOUNTABILITY





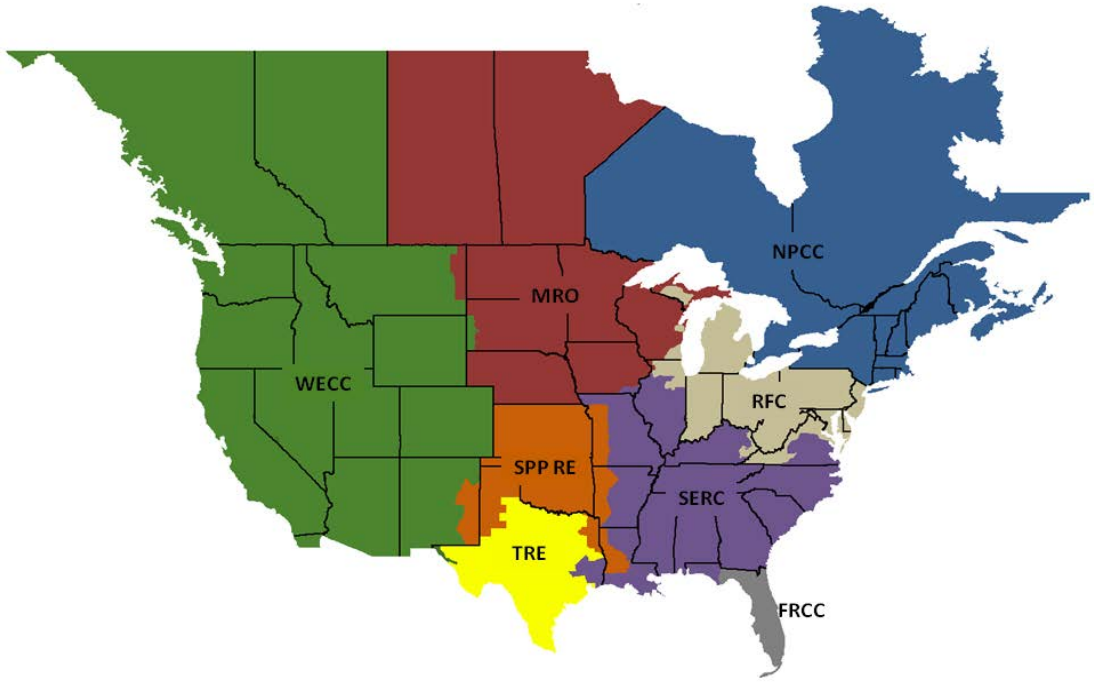

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Preface

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

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



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increased amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously, but instead may take up to several seconds. It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape has a strong influence on the hot spot heating of transformer windings and structural parts since thermal time constants of the transformer and time to peak of storm maxima are both on the order of minutes. The frequency content of the magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. Since geomagnetic disturbance impacts within areas of influence of approximately 100-200 km do not have a widespread impact on the interconnected transmission system (see Appendix I), statistical methods used to assess the frequency of occurrence of a severe GMD event need to consider broad geographical regions to avoid bias caused by spatially localized geomagnetic phenomena.

Benchmark GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [2]; thus, any benchmark event should consider the probability that the event will occur, as well as the impact or consequences of such an event. The benchmark event is composed of the following elements: 1) a reference peak geoelectric field amplitude (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 waveshape to facilitate time-domain analysis of GMD impact on equipment.

Reference Geoelectric Field Amplitude

The reference geoelectric field amplitude was determined through statistical analysis using the plane wave method [3]-[10] geomagnetic field measurements from geomagnetic observatories in northern Europe [11] and the reference (Quebec) earth model shown in **Table 1** [12]. For details of the statistical considerations, see Appendix I. The Quebec earth model is generally resistive and the geological structure is relatively well understood.

Table 1: Reference earth model (Quebec)

Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

The statistical analysis (see Appendix II) resulted in a conservative peak geoelectric field amplitude of approximately 8 V/km. For steady-state GIC and load flow analysis, the direction of the geoelectric field is assumed to be variable meaning that it can be in any direction (Eastward, Northward, or a vectorial combination thereof).

The frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years (see Appendix I). The selected frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is currently used as the storm return period for determining wind and ice loading of transmission infrastructure [13], for example.

The regional geoelectric field peak amplitude, E_{peak}, to be used in calculating GIC in the GIC system model can be obtained from the reference value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \quad (1)$$

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 (see Appendix II).

Reference Geomagnetic Field Waveshape

The reference geomagnetic field waveshape was selected after analyzing a number of recorded GMD events, including the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and the March 1989 GMD event that caused the Hydro Quebec blackout. The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory, was selected as the

reference geomagnetic field waveform because it provides generally conservative results when performing thermal analysis of power transformers (see Appendix I). The reference geomagnetic field waveshape is used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see **Figure 1**) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see **Figures 2** and **3**). Sampling rate for the geomagnetic field waveshape is 10 seconds.

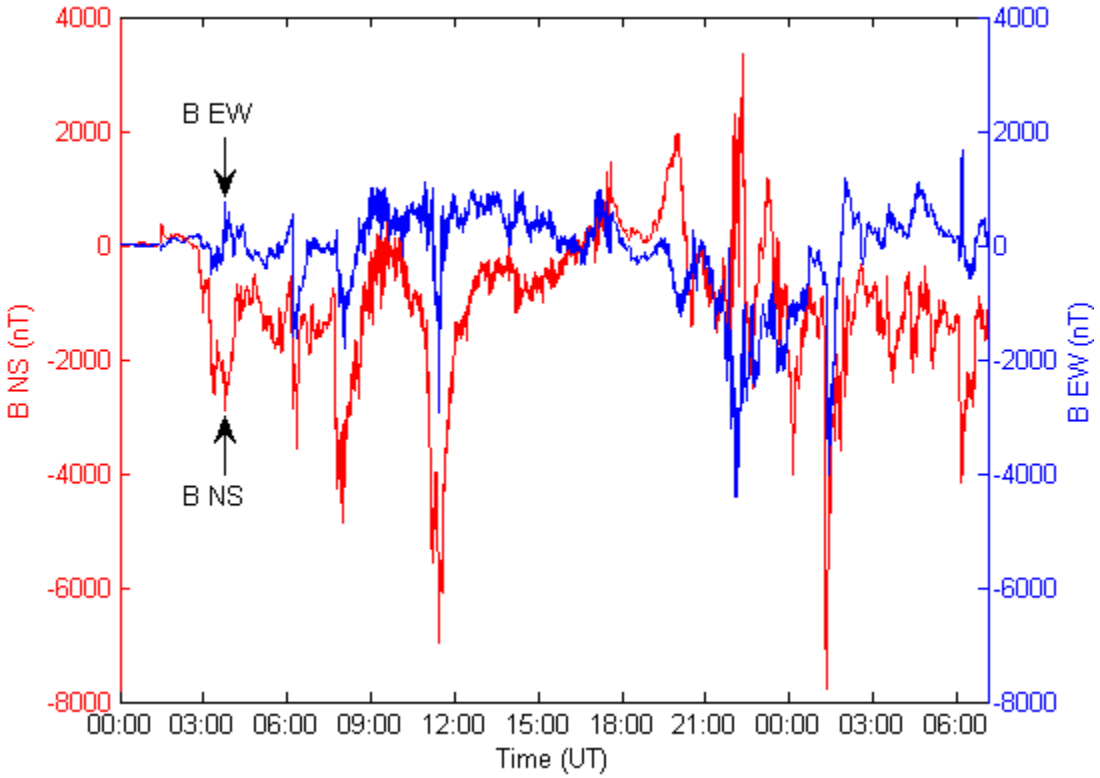


Figure 1: Benchmark Geomagnetic Field Waveshape
Red Bn (Northward), Blue Be (Eastward)
Referenced to pre-event quiet conditions

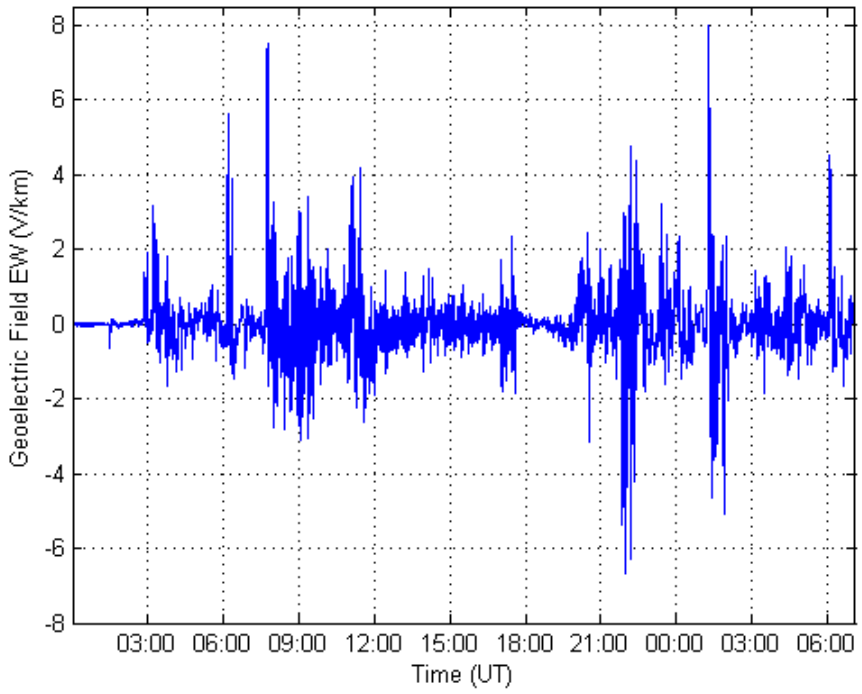


Figure 2: Benchmark Geoelectric Field Waveshape (E_E Eastward)

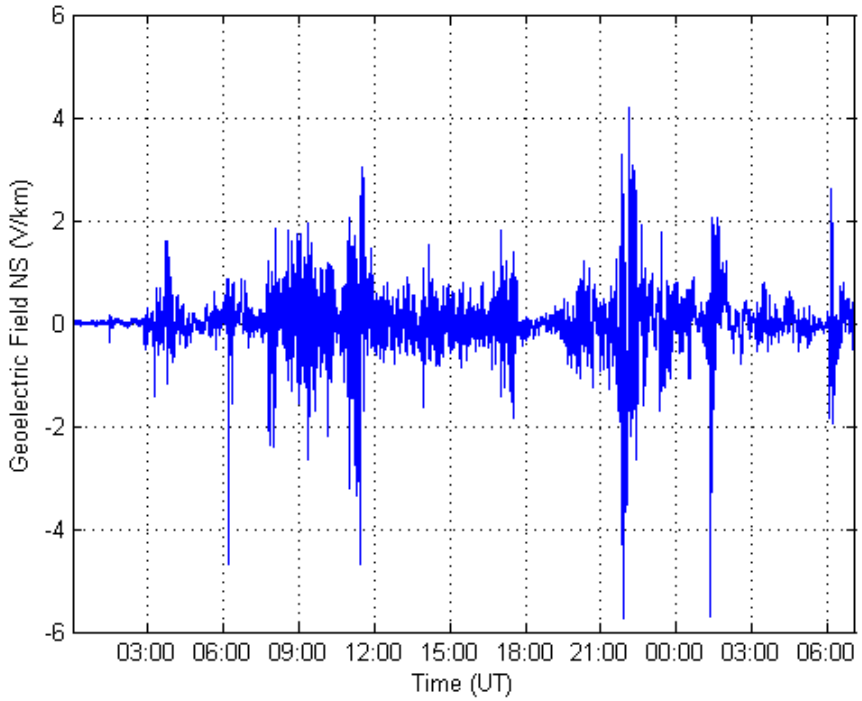


Figure 3: Benchmark Geoelectric Field Waveshape (E_N Northward)

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. The error bars in such analysis are significant, however, it is reasonable to conclude that statistically the March 1989 event is likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements, since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity features that result in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** is for illustration purposes only, and is not meant to suggest that a particular area is more likely to experience a localized enhanced geoelectric field.

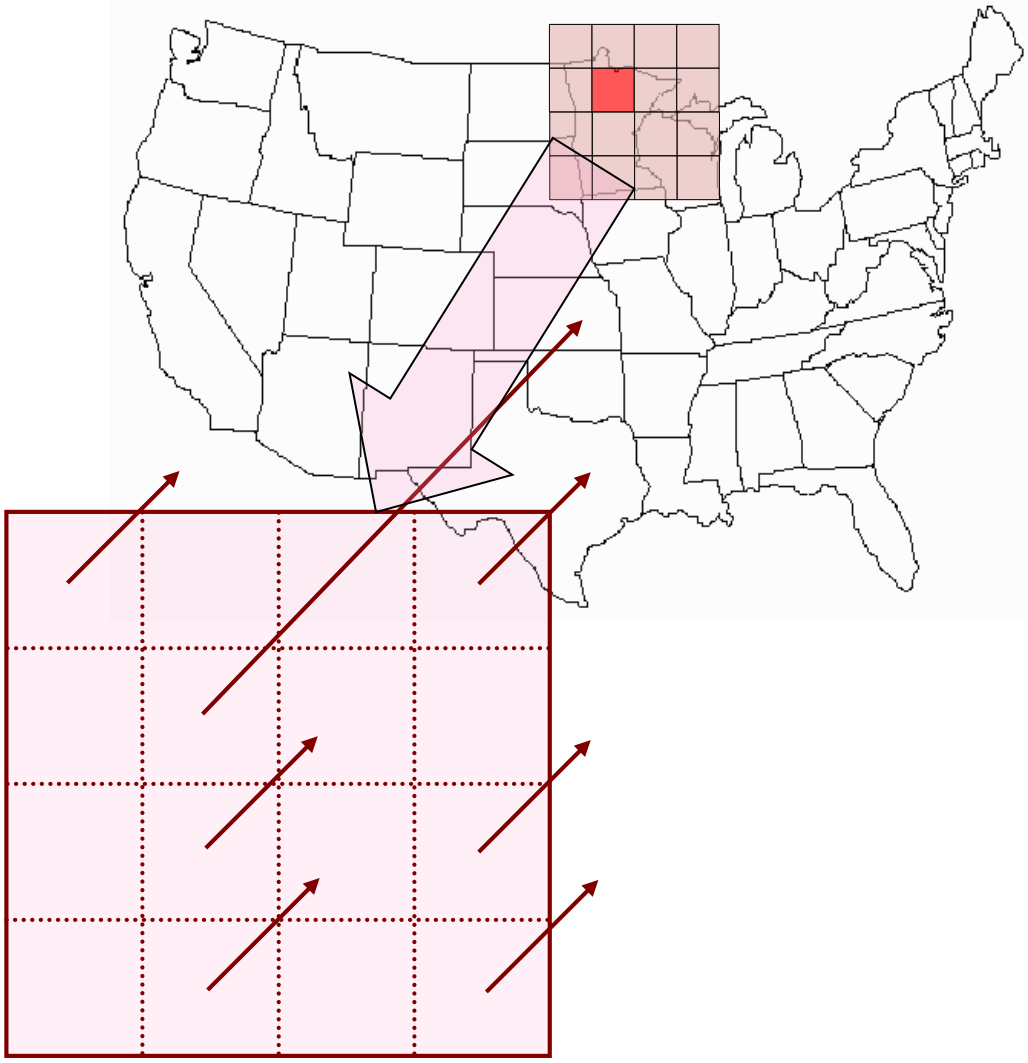


Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.
In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

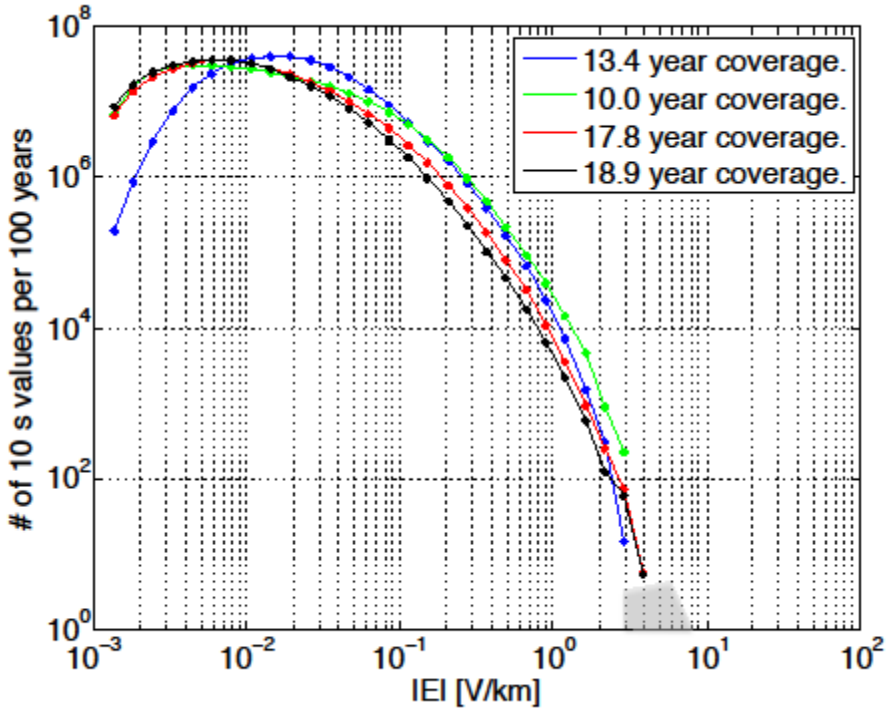


Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes.
Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

Extreme Value Analysis

The objective of extreme value analysis is to describe the behavior of a stochastic process at extreme deviations from the median. In general, the intent is to quantify the probability of an event more extreme than any previously observed. In particular, we are concerned with estimating the 95 percent confidence interval of the maximum geoelectric field amplitude to be expected within a 100-year return period.[3] In the context of this document, extreme value analysis has been used to rigorously support the extrapolation estimates used in the statistical considerations of the previous section.

The data set consists of 21 years of daily maximum geoelectric field amplitudes derived from the IMAGE magnetometer chain, using the Quebec earth model as reference. **Figure I-3** shows a scatter plot of the 10-largest geoelectric field amplitudes per year across the IMAGE stations. The plot indicates that both the amplitude and standard deviation of extreme geoelectric fields are not independent of the solar cycle. The data clearly exhibits heteroskedasticity[4] and an 11-year seasonality in the mean.

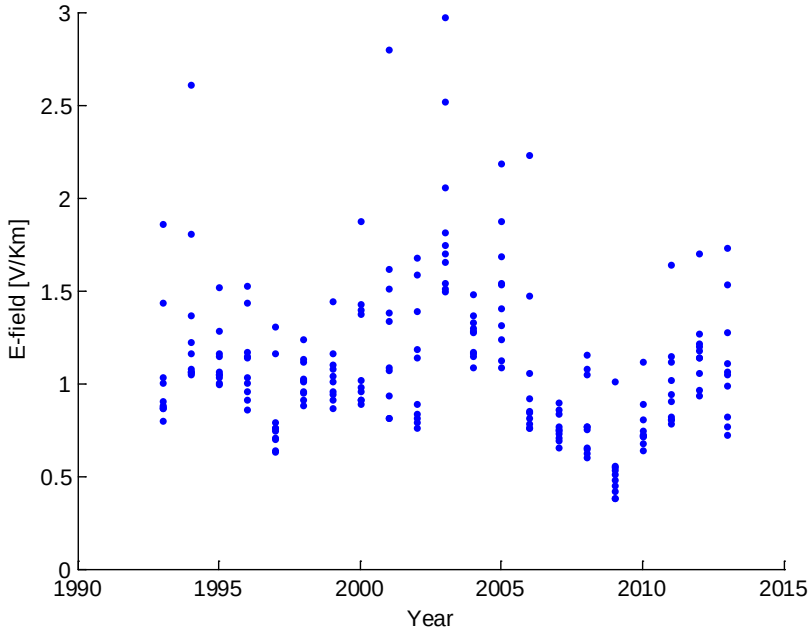


Figure I-3: Scatter Plot of Ten Largest Geoelectric Fields per Year

Data source: IMAGE magnetometer chain from 1993-2013

Several statistical methods can be used to conduct extreme value analysis. The most commonly applied include: Generalized Extreme Value (GEV), Point Over Threshold (POT), R-Largest, and Point Process (PP). In general, all methods assume independent and identically distributed (iid) data [23].

Two of these methods, GEV and POT, have been applied to the geoelectric field data, and their suitability for this application has been examined. **Table I-1** shows a summary of the estimated parameters and return levels obtained from GEV and POT methods. The parameters were estimated using the Maximum Likelihood Estimator (MLE). Since the distribution parameters do not have an intuitive interpretation, the expected geoelectric field amplitude for a 100-year return period is also included in **Table I-1.** The 95 percent confidence interval of the 100-year return level was calculated using the delta method and the profile likelihood. The delta method relies on the

[3] A 95 percent confidence interval means that, if repeated samples were obtained, the return level would lie within the confidence interval for 95 percent of the samples.

[4] Heteroskedasticity means that the skedastic function depends on the values of the conditioning variable; i.e., *var(Y|X=x) = f(x)*.

Gaussian approximation to the distribution of the MLE; this approximation can be poor for long return periods. In general, the profile likelihood provides a better description of the return level.

Table I-1: Extreme Value Analysis

Statistical Method	Estimated Parameters	Hypothesis Testing	100 Year Return Level Mean [V/km]	95% CI [V/km]	95% CI P-Likelihood [V/km]
(1) GEV	μ=1.4499 (0.1090) σ=0.4297 (0.0817) ξ=0.0305 (0.2011)	H0: ξ=0 p = 0.877	3.57	[1.77 , 5.36]	[2.71, 10.26]
(2) GEV $\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	β_0=1.5047 (0.0753) β_1=0.3722 (0.0740) σ=0.2894 (0.0600) ξ=0.1891 (0.2262)	H0: β_1=0 p= 0.0003 H0: ξ=0 p = 0.38	4	[2.64, 4.81]	[2.92, 12.33]
(3) POT, threshold=1V/km	σ=0.3163 (0.0382) ξ=0.0430 (0.0893)		3.4	[2.28, 4.52]	[2.72,5.64]
(4) POT, threshold=1V/km $\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	α_0=0.2920 (0.0339) α_1=0.1660 (0.0368) ξ=-0.0308 (0.0826)	H0: α_1=0 p= 3.7e-5	3.724	[2.64, 4.81]	[3.02, 5.77]

Statistical model (1) in **Table I-1** is the traditional GEV estimation using blocks of 1 year maxima; i.e., only 21 data points are used in the estimation. The mean expected amplitude of the geolectric field for a 100-year return level is 3.57 V/km. Since GEV works with blocks of maxima, it is typically regarded as a wasteful approach. This is reflected in the comparatively large confidence intervals: [1.77, 5.36] V/km for the delta method and [2.71, 10.26] V/km for the profile likelihood.

As discussed previously, GEV assumes that the data is iid. Based on the scatter plot shown in **Figure 1-3**, the iid statistical assumption is not warranted by the data. Statistical model (2) in **Table I-1** is a re-parameterization of the GEV distribution contemplating the 11-year seasonality in the mean,

$$\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where β_0 represents the offset in the mean, β_1 describes the 11-year seasonality, T is the period (11 years), and ϕ is a constant phase shift.

A likelihood ratio test is used to test the hypothesis that β_1 is zero. The null hypothesis, H0: β_1=0, is rejected with a p-value of 0.0003; as expected, the 11-year seasonality has explanatory power. The blocks of maxima during the solar minimum are better represented in the re-parameterized GEV. The benefit is an increase in the mean return

level to 4 V/km and a wider confidence interval: [2.63, 4.81] V/km for the delta method and [2.92, 12.33] V/km for the profile likelihood (calculated at solar maximum).

Statistical model (3) in **Table I-1** is the traditional POT estimation using a threshold *u* of 1 V/km; the data was de-clustered using a 1-day run. The data set consists of normalized excesses over a threshold, and therefore, the sample size for POT is increased if more than one extreme observation per year is available (in the GEV approach, only the maximum observation over the year was taken; in the POT method, a single year can have multiple observations over the threshold). The selection of the threshold *u* is a compromise between bias and variance. The asymptotic basis of the model relies on a high threshold; a threshold that is too low will likely lead to bias. On the other hand, a threshold that is too high will reduce the sample size and result in high variance. The stability of parameter estimates can guide the selection of an appropriate threshold. **Figure I-4** shows the estimated parameters (modified scale $\sigma^*=\sigma_u-\xi\cdot u$, and shape ξ) for a range of thresholds. The objective is to select the lowest threshold for which the estimates remain near constant; 1V/km appears to be a good choice.

The mean return level for statistical model (3), 3.4 V/km, is similar to the GEV estimates. However, due to the larger sample size, the POT method is more efficient, and consequently, the confidence intervals are significantly reduced: [2.28, 4.52] V/km for the delta method, and [2.72, 5.64] V/km for the profile likelihood method.

In order to cope with the heteroskedasticity exhibited by the data, a re-parameterization of POT is used in statistical model (4) in **Table I-1**,

$$\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where α_0 represents the offset in the standard deviation, α_1 describes the 11-year seasonality, *T* is the period ($365.25 \cdot 11$), and ϕ is a constant phase shift.

The parameter α_1 is statistically significant; the null hypothesis, H0: $\alpha_1=0$, is rejected with a p-value of 3.7e-5. The mean return level has slightly increased to 3.72 V/km. The upper limit of the confidence interval, calculated at solar maximum, also increases: [2.63, 4.81] V/km for the delta method and [3.02, 5.77] V/km for the profile likelihood method. As a final remark, it is emphasized that the confidence interval obtained using the profile likelihood is preferred over the delta method. **Figure I-5** shows the profile likelihood of the 100-year return level of statistical model (4). Note that the profile likelihood is highly asymmetric with a positive skew, rendering a larger upper limit for the confidence interval. Recall that the delta method assumes a normal distribution for the MLEs, and therefore, the confidence interval is symmetric around the mean.

To conclude, traditional GEV (1) and POT (3) models are misspecified; the statistical assumptions (iid) are not warranted by the data. The models were re-parameterized to cope with heteroskedasticity and the 11-year seasonality in the mean. Statistical model (4) better utilizes the available extreme measurements and it is therefore preferred over statistical model (2). The upper limit of the 95 percent confidence interval for a 100-year return level is 5.77 V/km. This analysis is consistent with the selection of a geoelectric field amplitude of 8 V/km for the 100-year GMD benchmark. .

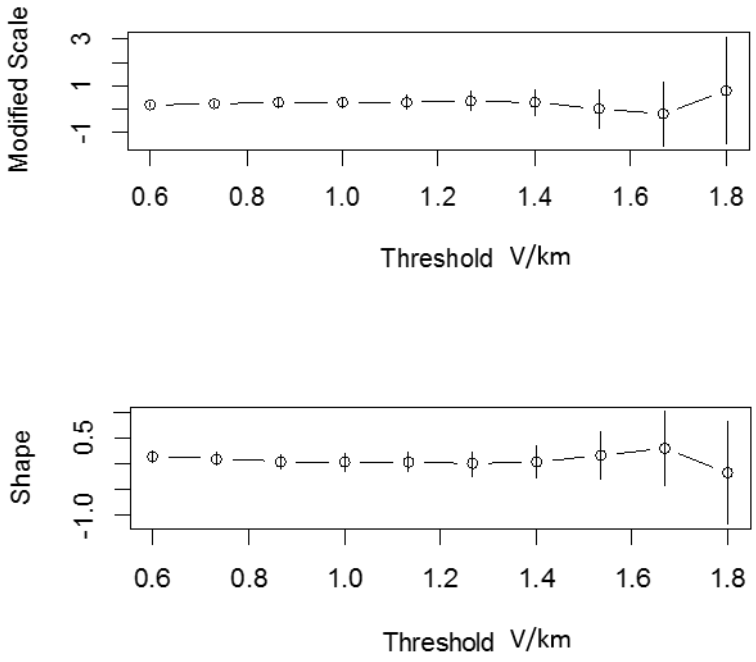


Figure I-4: Parameter Estimates Against Threshold for Statistical Model (3)

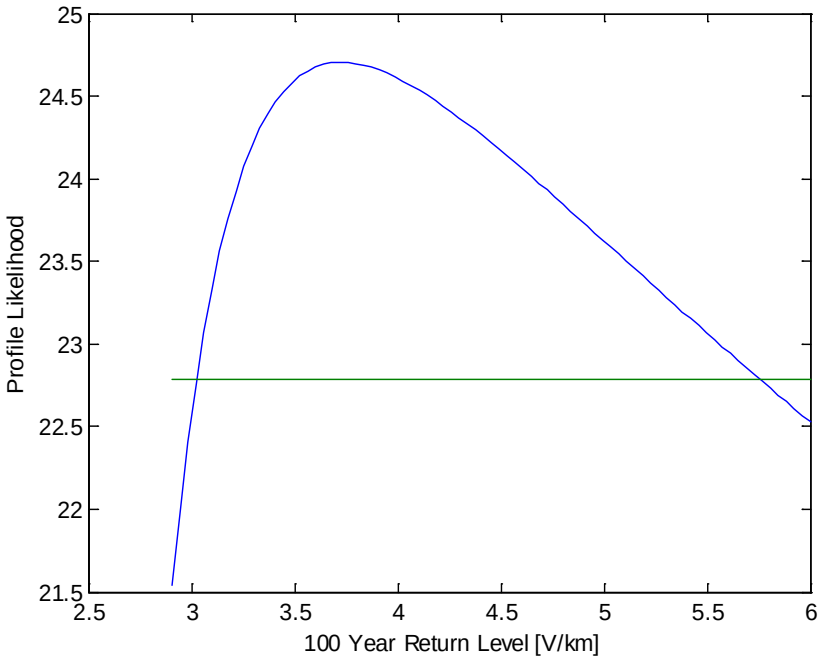


Figure I-5: Profile Likelihood for 100-year Return Level for Statistical Model (4)

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

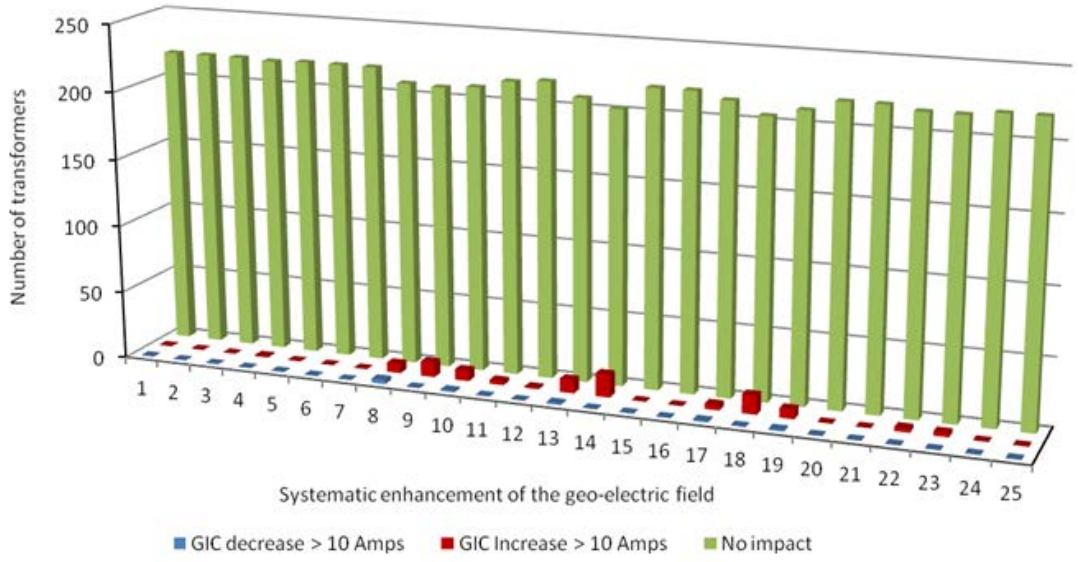


Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

as the measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003 described in the NERC GMD interim report of 2012 [14].

To illustrate, the results of a thermal analysis performed on a relatively large test network with a diverse mix of circuit lengths and orientations is provided in **Figures I-7** and **I-8**. **Figure I-9** shows a more systematic way to compare the relative effects of storm waveshape on the thermal response of a transformer. It shows the results of 33,000 thermal assessments for all combinations of effective GIC due to circuit orientation (similar **to Figures I-7** and **I-8** but systematically taking into account all possible circuit orientations). These results illustrate the relative effect of different waveshapes in a broad system setting and should not be interpreted as a vulnerability assessment of any particular network.

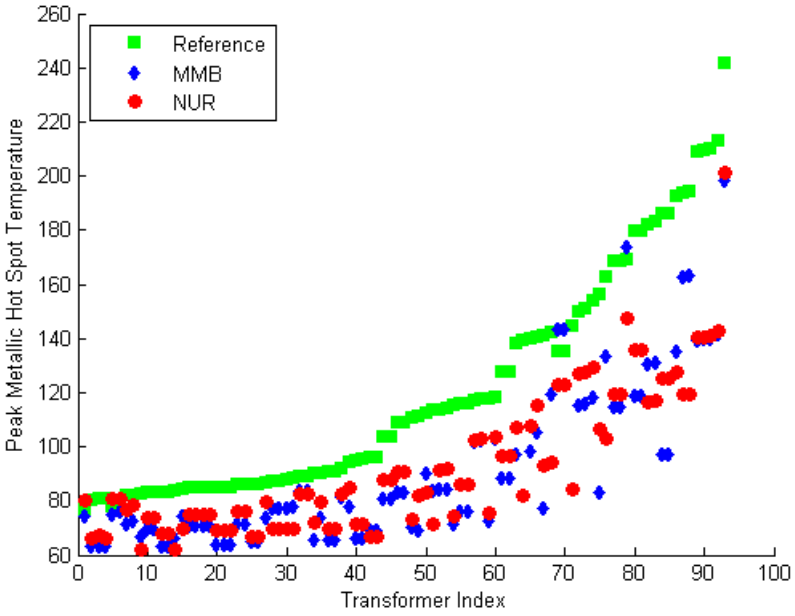


Figure I-7: Calculated Peak Metallic Hot Spot Temperature for All Transformers in a Test System with a Temperature Increase of More Than 20°C for Different GMD Events Scaled to the Same Peak Geoelectric Field

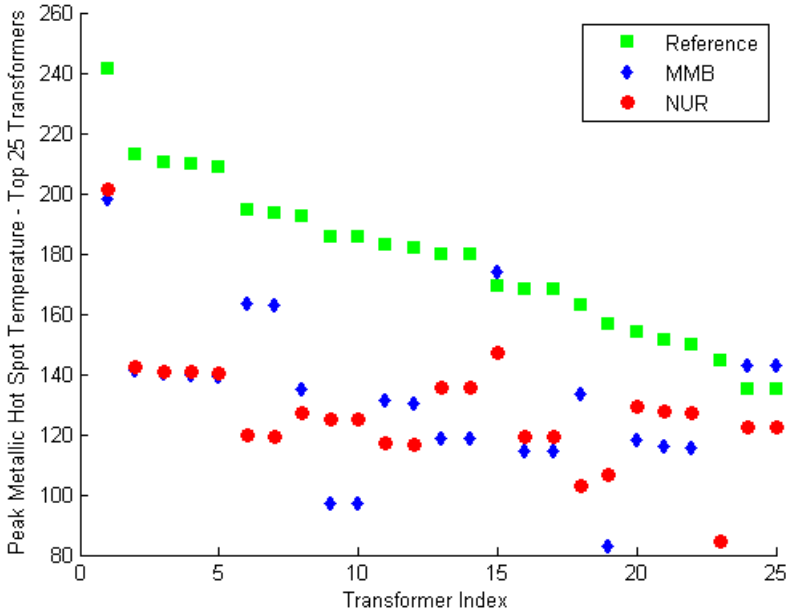


Figure I-8: Calculated Peak Metallic Hot Spot Temperature for the Top 25 Transformers in a Test System for Different GMD Events Scaled to the Same Peak Geoelectric Field

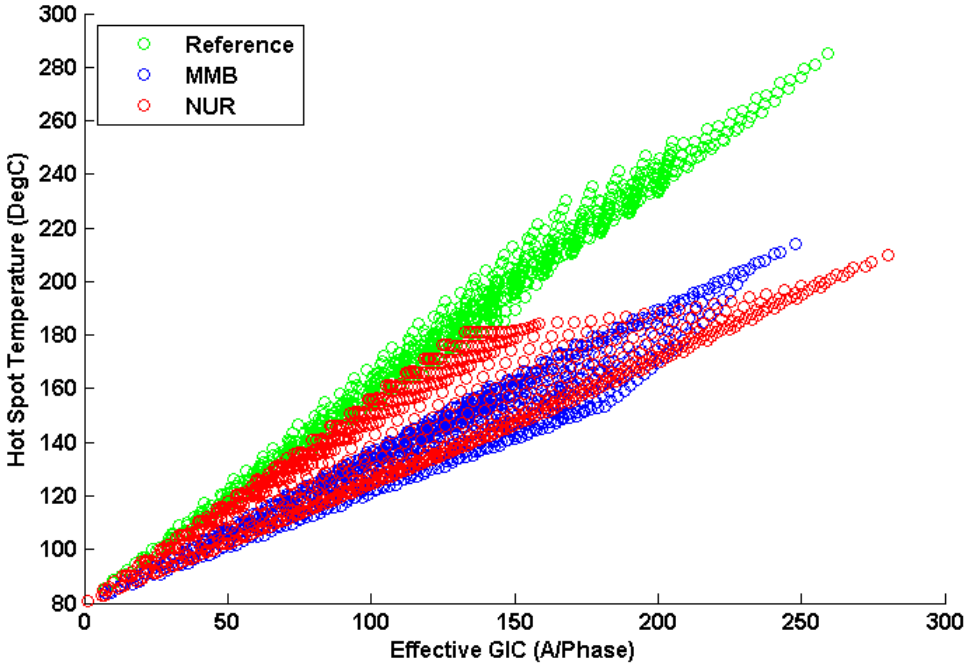


Figure I-9: Calculated Peak Metallic Hot Spot Temperature for all possible circuit orientations and effective GIC.

Appendix II – Scaling the Benchmark GMD Event

The intensity of a GMD event depends on geographical considerations such as geomagnetic latitude[6] and local earth conductivity[7] [3]**.** Scaling factors for geomagnetic latitude take into consideration that the intensity of a GMD event varies according to latitude-based geographical location. Scaling factors for earth conductivity take into account that the induced geoelectric field depends on earth conductivity, and that different parts of the continent have different earth conductivity and deep earth structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. To allow usage of the reference geomagnetic field waveshape in other locations, **Table II-1** summarizes the scaling factor α correlating peak geoelectric field to geomagnetic latitude as described in **Figure II-1** [3]. This scaling factor α has been obtained from a large number of global geomagnetic field observations of all major geomagnetic storms since the late 1980s [15], [24]-[25], and can be approximated with the empirical expression in (II.1)

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \qquad \text{(II.1)}$$

where L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1.0$.

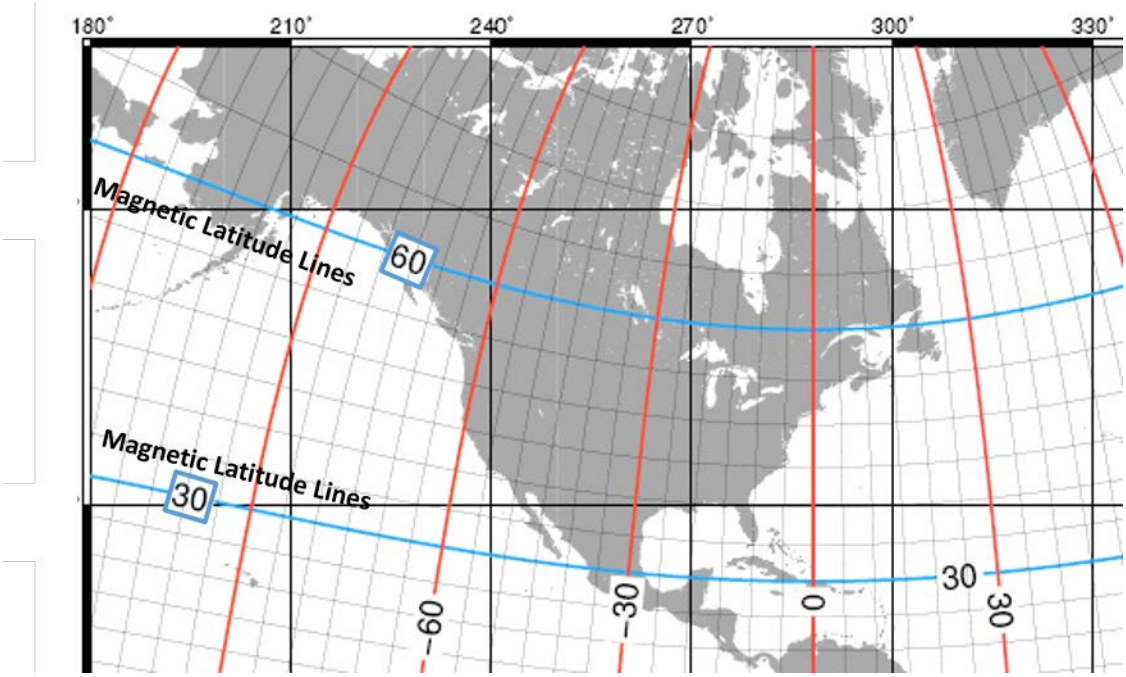


Figure II-1: Geomagnetic Latitude Lines in North America

[6] Geomagnetic latitude is analogous to geographic latitude, except that bearing is in relation to the magnetic poles, as opposed to the geographic poles. Geomagnetic phenomena are often best organized as a function of geomagnetic coordinates.

[7] Local earth conductivity refers to the electrical characteristics to depths of hundreds of km down to the earth's mantle. In general terms, lower ground conductivity results in higher geoelectric field amplitudes.

Table II-1: Geomagnetic Field Scaling Factors	
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 provided in **Table 1**. This earth model has been used in many peer-reviewed technical articles [12, 15]. The peak geoelectric field depends on the geomagnetic field waveshape and the local earth conductivity. Ideally, the peak geoelectric field, E_{peak}, is obtained by calculating the geoelectric field from the scaled geomagnetic waveshape using the plane wave method and taking the maximum value of the resulting waveforms

$$E_N = (z(t)/\mu_o) * B_E(t)$$
$$E_E = -(z(t)/\mu_o) * B_N(t) \qquad \text{(II.2)}$$
$$E_{peak} = \max\left\{\left|E_E(t), E_N(t)\right|\right\}$$

where,

* denotes convolution in the time domain,

z(t) is the impulse response for the earth surface impedance calculated from the laterally uniform or 1D earth model,

$B_E(t)$, $B_N(t)$ are the scaled Eastward and Northward geomagnetic field waveshapes,

$E_E(t)$, $E_N(t)|$ are the magnitudes of the calculated Eastward and Northward geoelectric field $E_E(t)$ and $E_N(t)$.

As noted previously, the response of the earth to B(t) (and dB/dt) is frequency dependent. **Figure II-2** shows the magnitude of Z(ω) for the reference earth model.

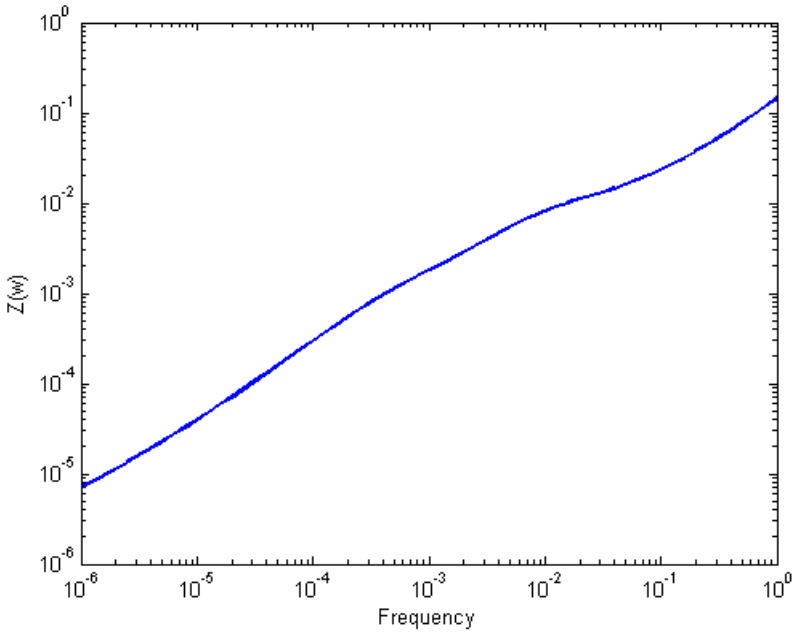


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

If a utility does not have the capability of calculating the waveshape or time series for the geoelectric field, an earth conductivity scaling factor β can be obtained from **Table II-2**. Using α and β, the peak geoelectric field E_{peak} for a specific service territory shown in **Figure II-3** can be obtained using (II.3)

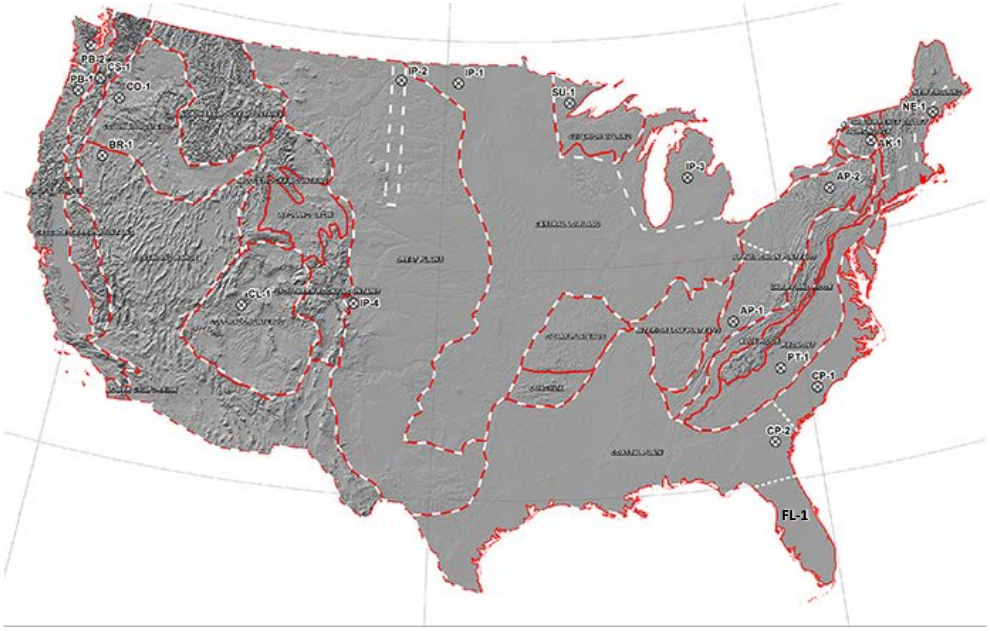
$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \quad \text{(II.3)}$$

It should be noted that (II.3) is an approximation based on the following assumptions:

- The earth models used to calculate Table II-2 for the United States are from published information available on the USGS website.
- The models used to calculate Table II-2 for Canada were obtained from NRCan and reflect the average structure for large regions. When models are developed for sub-regions, there will be variance (to a greater or lesser degree) from the average model. For instance, detailed models for Ontario have been developed by NRCan and consist of seven major sub-regions.
- The conductivity scaling factor β is calculated as the quotient of the local geoelectric field peak amplitude in a physiographic region with respect to the reference peak amplitude value of 8 V/km. Both geoelectric field peaks amplitudes are calculated using the reference geomagnetic field time series. If a different geomagnetic field time series were used, the calculated scaling factors β would be different than the values in Table II-2 because the frequency content of storm maxima is, in principle, different for every storm. However, the reference time series produces generally more conservative values of β when compared to the time series of reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and other recordings of the March 1989 event at high latitudes (Meanook observatory, Canada). The average variation between minimum and maximum β is approximately 12 percent. **Figure II-4** illustrates the values of β calculated using the 10-second recordings for these geomagnetic field time series.
- If a utility has technically-sound earth models for its service territory and sub-regions thereof, then the use of such earth models is preferable to estimate E_{peak}.

- 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.

Physiographic Regions of the Continental United States



Physiographic Regions of Canada



Figure II-3: Physiographic Regions of North America

Table II-2 Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
FL1	0.74
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

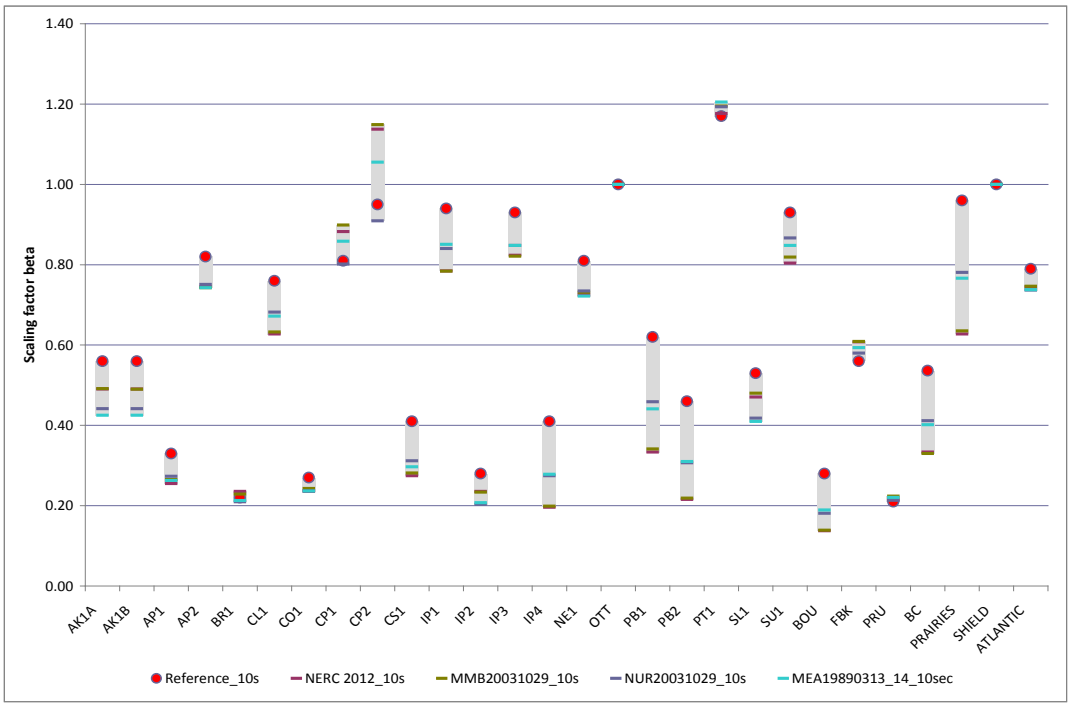


Figure II-4: Beta factors Calculated for Different GMD Events
Red circles correspond to the values in Table II-2

Example Calculations

Example 1

Consider a transmission service territory that lies in a geographical latitude of 45.5°, which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly. If the service territory has the same earth conductivity as the benchmark then β=1, and the peak geoelectric field will be

$$\alpha = 0.56$$
$$\beta = 1.0$$
$$E_{peak} = 8 \times 0.56 \times 1 = 4.5 V/km$$

If the service territory spans more than one physiographic region (i.e. several locations within the service territory have a different earth model) then the largest α can be used across the entire service territory for conservative results. Alternatively, the network can be split into multiple subnetworks, and the corresponding geoelectric field amplitude can be applied to each subnetwork.

Example 2

Consider a service territory that lies in a geographical latitude of 45.5° which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly.

The service territory has lower conductivity than the reference benchmark conductivity, therefore, according to the conductivity factor β from Table II-2., the calculation follows:

Conductivity factor β=1.17

$$\alpha = 0.56$$

$$E_{peak} = 8 \times 0.56 \times 1.17 = 5.2V / km$$

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Screening Criterion for Transformer Thermal Impact Assessment

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events

Summary

Proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events requires applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. The standard requires transformer thermal impact assessments to be performed on power transformers with high side, wye-grounded windings with terminal voltage greater than 200 kV. Transformers are exempt from the thermal impact assessment requirement if the maximum effective geomagnetically-induced current (GIC) in the transformer is less than 75 A per phase as determined by GIC analysis of the system. Based on published power transformer measurement data as described below, an effective GIC of 75 A per phase is a conservative screening criterion. To provide an added measure of conservatism, the 75 A per phase threshold, although derived from measurements in single-phase units, is applicable to transformers with all core types (e.g., three-limb, three-phase).

Justification

Applicable entities are required to carry out a thermal assessment with GIC(t) calculated using the benchmark GMD event geomagnetic field time series or waveshape for effective GIC values above a screening threshold. The calculated GIC(t) for every transformer will be different because the length and orientation of transmission circuits connected to each transformer will be different even if the geoelectric field is assumed to be uniform. However, for a given thermal model and maximum effective GIC there are upper and lower bounds for the peak hot spot temperatures. These are shown in **Figure 1** using three available thermal models based on direct temperature measurements.

The results shown in **Figure 1** summarize the peak metallic hot spot temperatures when GIC(t) is calculated using (1), and systematically varying GIC_E and GIC_N to account for all possible orientation of circuits connected to a transformer. The transformer GIC (in A/phase) for any value of E_E (t) and E_N(t) can be calculated using equation (1) from reference [1].

$$GIC(t) = \left|E(t)\right| \cdot \left\{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\right\} \quad (1)$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \tag{2}$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \tag{3}$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \tag{4}$$

GIC_N is the effective GIC due to a northward geoelectric field of 1 V/km, and GIC_E is the effective GIC due to an eastward geoelectric field of 1 V/km. The units for GIC_N and GIC_E are A/phase/V/km.

It should be emphasized that with the thermal models used and the benchmark GMD event geomagnetic field waveshape, peak hot spot temperatures must lie below the envelope shown in **Figure 1**. The x-axis in Figure 1 corresponds to the absolute value of peak GIC(t). Effective maximum GIC for a transformer corresponds to a worst-case geoelectric field orientation, which is network-specific. Figure 1 represents a possible range, not the specific thermal response for a given effective GIC and orientation.

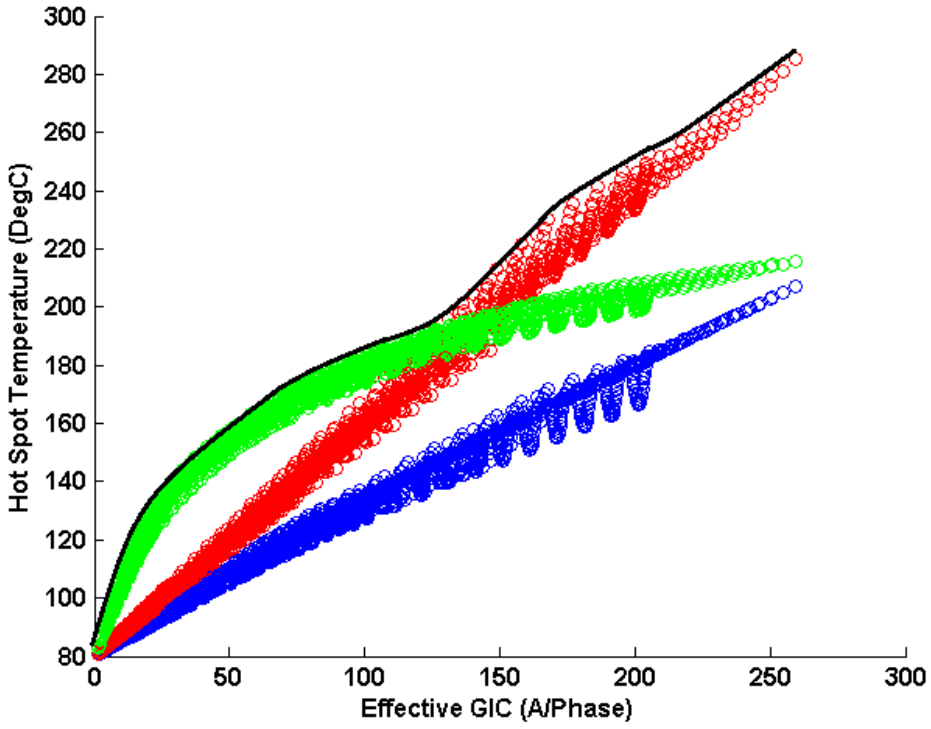


Figure 1: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: SVC coupling transformer model [2]. Blue: Fingrid model [3]. Green: Autotransformer model [4].

Consequently, with the most conservative thermal models known at this point in time, the peak metallic hot spot temperature obtained with the benchmark GMD event waveshape assuming an effective GIC magnitude of 75 A per phase will result in a peak temperature between 160°C and 172°C when the bulk oil temperature is 80°C (full load bulk oil temperature). The upper boundary of 172°C remains well below the metallic hot spot 200°C threshold for short-time emergency loading suggested in IEEE Std C57.91-2011 [5] (see Table 1).

TABLE 1:
Excerpt from Maximum Temperature Limits Suggested in IEEE C57.91-2011

	Normal life expectancy loading	Planned loading beyond nameplate rating	Long-time emergency loading	Short-time emergency loading
Insulated conductor hottest-spot temperature °C	120	130	140	180
Other metallic hot-spot temperature (in contact and not in contact with insulation), °C	140	150	160	200
Top-oil temperature °C	105	110	110	110

The selection of the 75 A per phase screening threshold is based on the following considerations:

- A thermal assessment using the most conservative thermal models known to date will not result in peak hot spot temperatures above 172°C. Transformer thermal assessments should not be required by Reliability Standards when results will fall well below IEEE Std C57.91-2011 limits.
- Applicable entities may choose to carry out a thermal assessment when the effective GIC is below 75 A per phase to take into account the age or condition of specific transformers where IEEE Std C57.91- 2011 limits could be assumed to be lower than 200°C.
- The models used to determine the 75 A per phase screening threshold are known to be conservative at higher values of effective GIC, especially the SVC coupling transformer model in [2].
- Thermal models in peer-reviewed technical literature, especially those calculated models without experimental validation, are less conservative than the models used to determine the screening threshold. Therefore, a technically-justified thermal assessment for effective GIC below 75 A per phase using the benchmark GMD event geomagnetic field waveshape will always result in a "pass" on the basis of the state of the knowledge at this point in time.
- Based on simulations, the 75 A per phase screening threshold will result in a maximum instantaneous peak hot spot temperature of 172°C. However, IEEE Std C57.91- 2011 limits assume short term emergency operation (typically 30 minutes). As illustrated in **Figure 2**, simulations of the 75 A per phase screening threshold result in 30-minute duration hot spot temperatures of about

155°C. The threshold provides an added measure of conservatism in not taking into account the duration of hot spot temperatures.

- The models used in the determination of the threshold are conservative but technically justified.
- Winding hot spots are not the limiting factor in terms of hot spots due to half-cycle saturation, therefore the screening criterion is focused on metallic part hot spots only.

The 75 A per phase screening threshold was determined using single-phase transformers, but is applicable to all types of transformer construction. While it is known that some transformer types such as three-limb, three-phase transformers are intrinsically less susceptible to GIC, it is not known by how much, on the basis of experimentally-supported models.

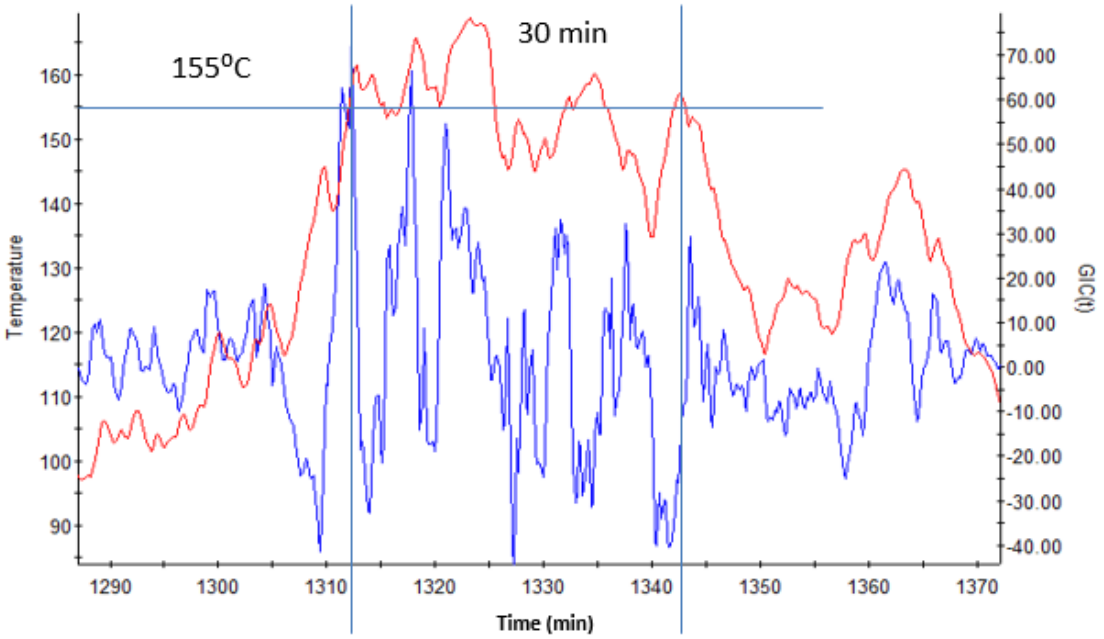


Figure 2: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: metallic hot spot temperature. Blue: GIC(t) that produces the maximum hot spot temperature with peak GIC(t) scaled to 75 A/phase.

Appendix

The envelope used for thermal screening (Figure 1) is derived from two thermal models. The first is based on laboratory measurements carried out on 500/16.5 kV 400 MVA single-phase Static Var Compensator (SVC) coupling transformer [2]. Temperature measurements were carried out at relatively small values of GIC (see **Figure 3**). The asymptotic thermal response for this model is the linear extrapolation of the known measurement values. Although the near-linear behavior of the asymptotic thermal response is consistent with the measurements made on a Fingrid 400 kV 400 MVA five-leg core-type fully-wound transformer [3] (see **Figures 4 and 5**), the extrapolation from low values of GIC is very conservative, but reasonable for screening purposes.

The second transformer model is based on a combination of measurements and modeling for a 400 kV 400 MVA single-phase core-type autotransformer [4] (see **Figures 6 and 7**). The asymptotic thermal behavior of this transformer shows a "down-turn" at high values of GIC as the tie plate increasingly saturates but relatively high temperatures for lower values of GIC. The hot spot temperatures are higher than for the two other models for GIC less than 125 A per phase.

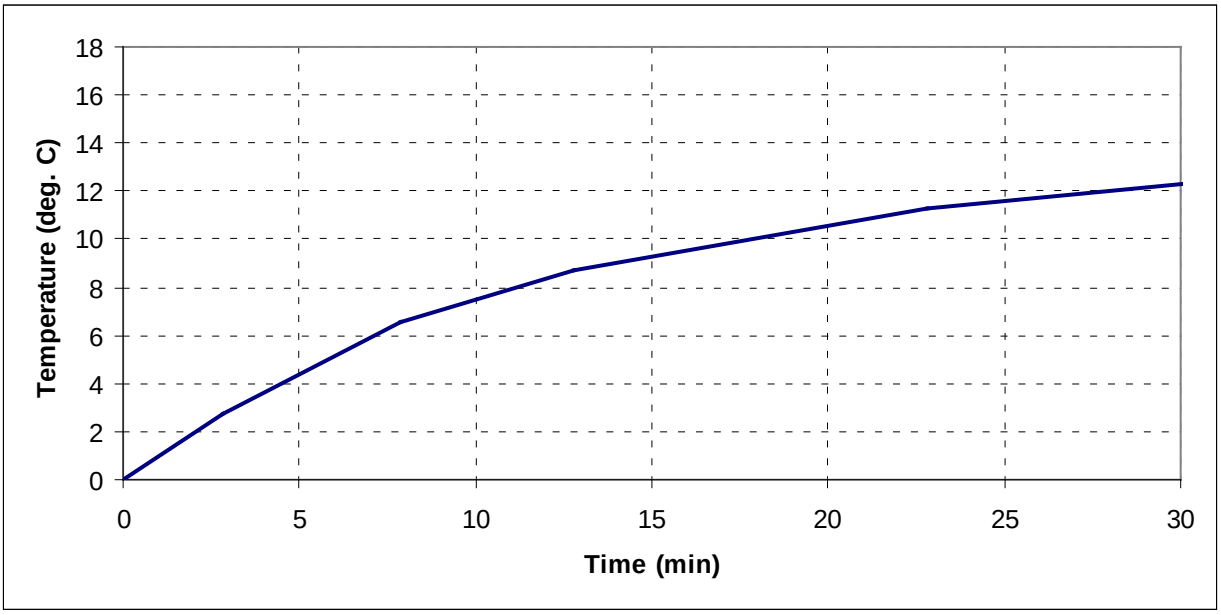


Figure 3: Thermal step response of the tie plate of a 500 kV 400 MVA single-phase SVC coupling transformer to a 5 A per phase dc step.

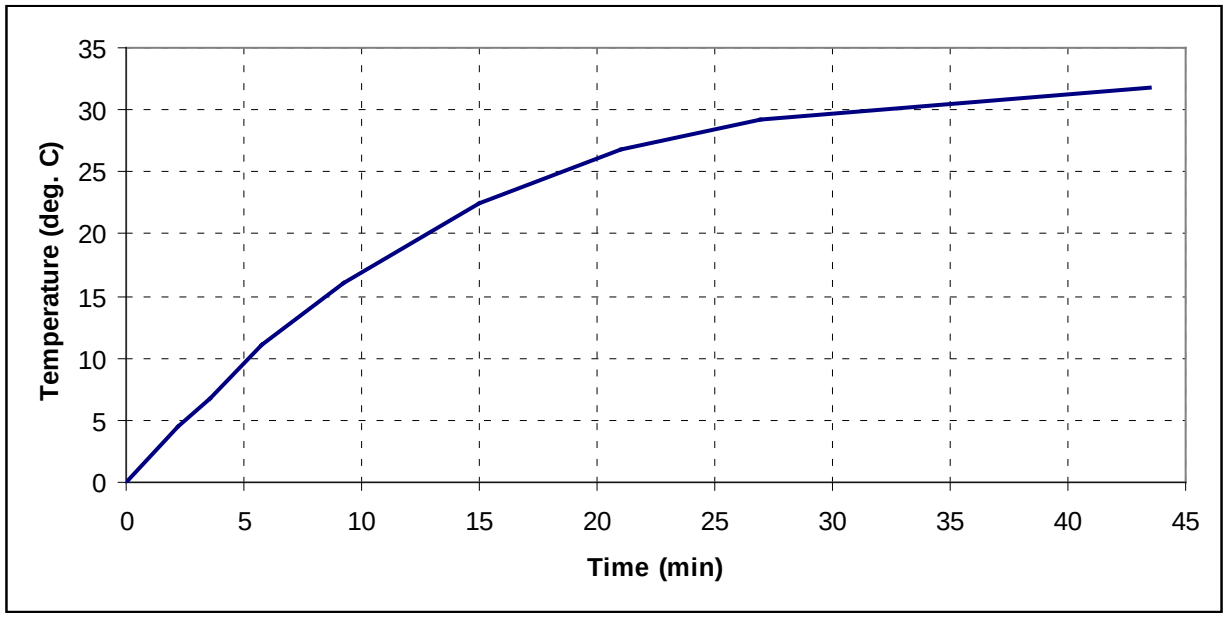


Figure 4: Step thermal response of the top yoke clamp of a 400 kV 400 MVA five-leg core-type fully-wound transformer to a 16.67 A per phase dc step.

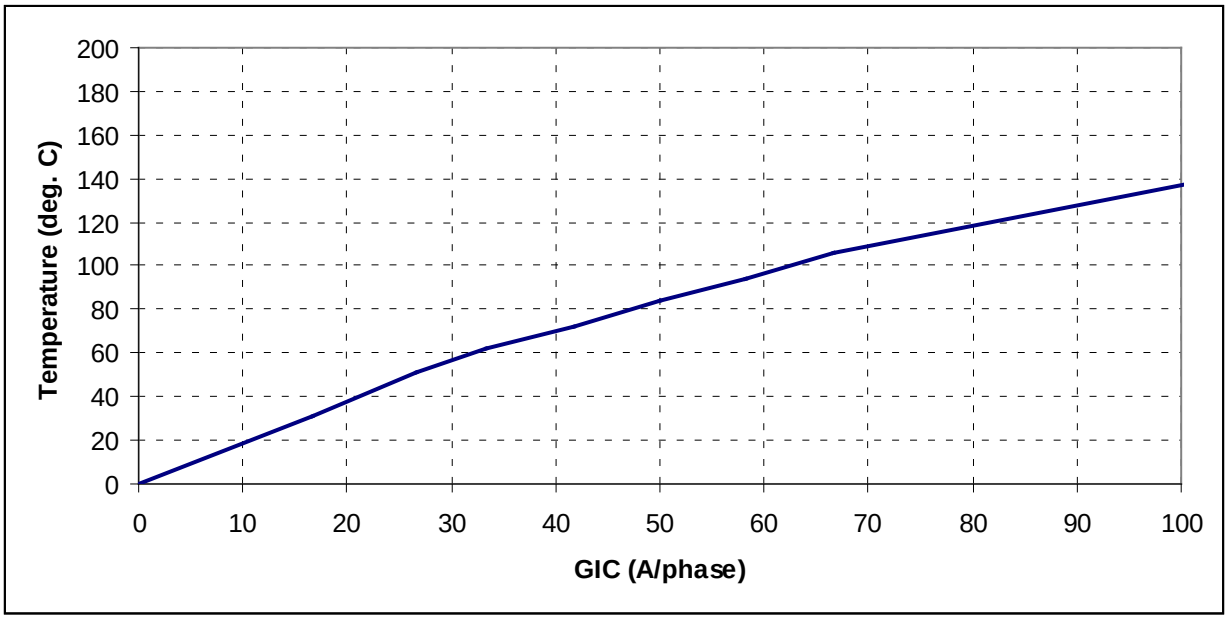


Figure 5: Asymptotic thermal response of the top yoke clamp of a 400 kV 400 MVA five-leg core-type fully-wound transformer.

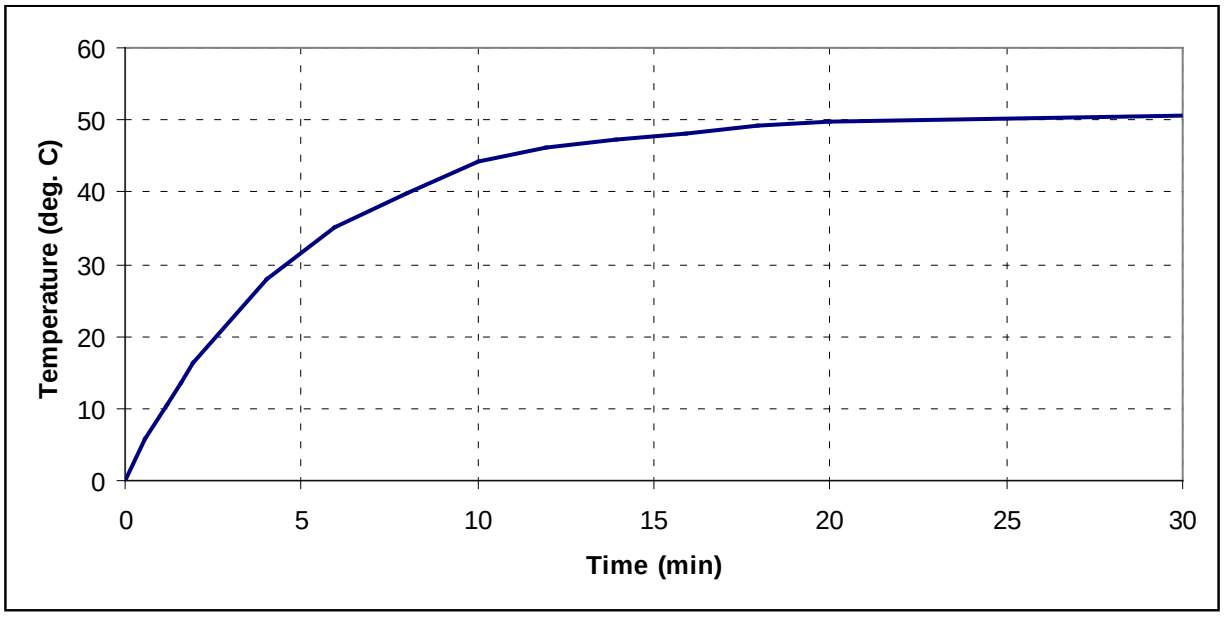


Figure 6: Step thermal response of the tie plate of a 400 kV 400 MVA single-phase core-type autotransformer to a 10 A per phase dc step.

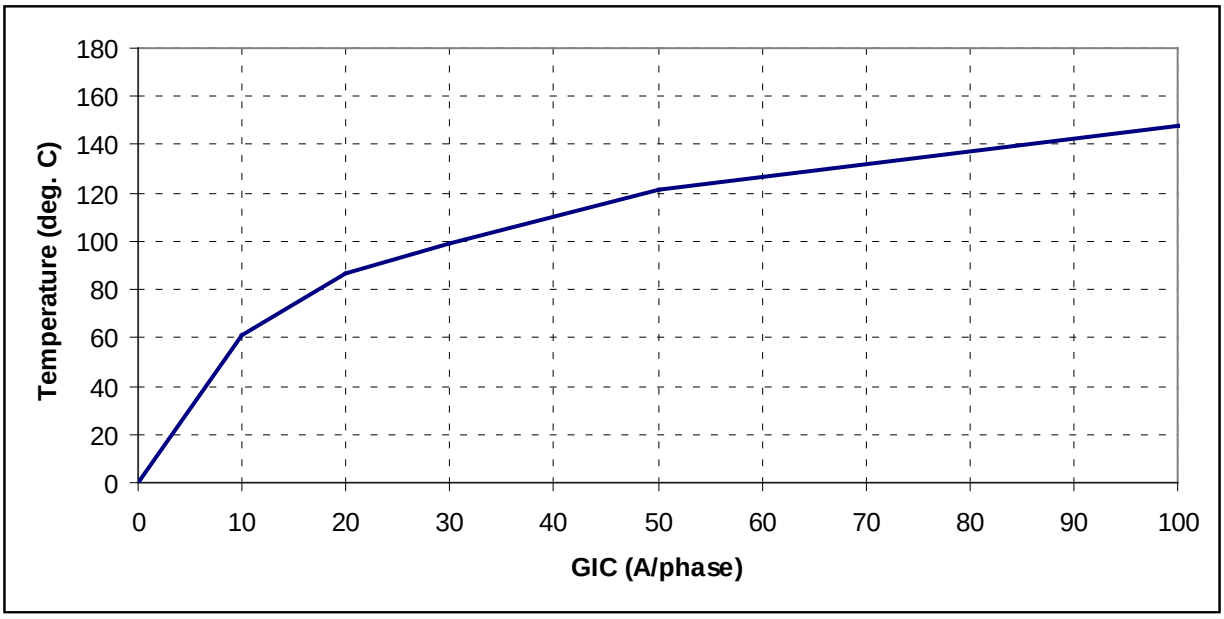


Figure 7: Asymptotic thermal response of the tie plate of a 400 kV 400 MVA single-phase core-type autotransformer.

The envelope in **Figure 1** can be used as a conservative thermal assessment for effective GIC values of 75 A per phase and greater (see Table 2).

Table 2: Upper Bound of Peak Metallic Hot Spot Temperatures Calculated Using the Benchmark GMD Event

Effective GIC (A/phase)	Metallic hot spot Temperature (°C)	Effective GIC(A/phase)	Metallic hot spot Temperature (°C)
0	80	100	182
10	107	110	186
20	128	120	190
30	139	130	193
40	148	140	204
50	157	150	213
60	169	160	221
70	170	170	230
75	172	180	234
80	175	190	241
90	179	200	247

For instance, if effective GIC is 130 A per phase and oil temperature is assumed to be 80°C, peak hot spot temperature is 193°C. This value is below the 200°C IEEE Std C57.91-2011 threshold for short time emergency loading and this transformer will have passed the thermal assessment. If the full heat run oil temperature is 67°C at maximum ambient temperature, then 150 A per phase of effective GIC translates into a peak hot spot temperature of 200°C and the transformer will have passed. If the limit is lowered to 180°C to account for the condition of the transformer, then this would be an indication to "sharpen the pencil" and perform a detailed assessment. Some methods are described in Reference [1].

The temperature envelope in Figure 1 corresponds to the values of effective GIC that result in the highest temperature for the benchmark GMD event. Different values of effective GIC could result in lower temperatures using the same model. For instance, the difference in upper and lower bounds of peak temperatures for the SVC coupling transformer model for 150 A per phase is approximately 30°C. In this case, GIC(t) should be generated to calculate the peak temperatures for the actual configuration of the transformer within the system as described in Reference [1]. Alternatively, a more precise thermal assessment could be carried out with a thermal model that more closely represents the thermal behavior of the transformer under consideration.

References

[1] Transformer Thermal Impact Assessment white paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[2] Marti, L., Rezaei-Zare, A., Narang, A., "Simulation of Transformer Hotspot Heating due to Geomagnetically Induced Currents," *IEEE Transactions on Power Delivery,* vol.28, no.1, pp.320-327, Jan. 2013.

[3] Lahtinen, Matti. Jarmo Elovaara. "GIC occurrences and GIC test for 400 kV system transformer". IEEE Transactions on Power Delivery, Vol. 17, No. 2. April 2002.

[4] J. Raith, S. Ausserhofer: "GIC Strength verification of Power Transformers in a High Voltage Laboratory", GIC Workshop, Cape Town, April 2014

[5] "IEEE Guide for loading mineral-oil-immersed transformers and step-voltage regulators." IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995).

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Transformer Thermal Impact Assessment White Paper

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events

Background

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances (GMDs) in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard to specifically address the Stage 2 directives in Order No. 779.

Large power transformers connected to the EHV transmission system can experience both winding and structural hot spot heating as a result of GMD events. TPL-007-1 will require owners of such transformers to conduct thermal analyses of their transformers to determine if the transformers will be able to withstand the thermal transient effects associated with the Benchmark GMD event. This paper discusses methods that can be employed to conduct such analyses, including example calculations.

The primary impact of GMDs on large power transformers is a result of the quasi-dc current that flows through wye-grounded transformer windings. This geomagnetically-induced current (GIC) results in an offset of the ac sinusoidal flux resulting in asymmetric or half-cycle saturation (see **Figure 1**).

Half-cycle saturation results in a number of known effects:

- Hot spot heating of transformer windings due to harmonics and stray flux;
- Hot spot heating of non-current carrying transformer metallic members due to stray flux;
- Harmonics;
- Increase in reactive power absorption; and
- Increase in vibration and noise level.

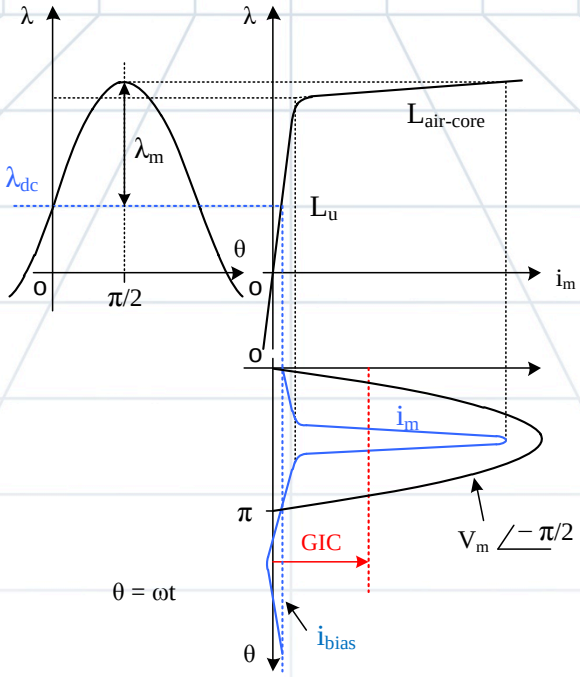


Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

This paper focuses on hot spot heating of transformer windings and non current-carrying metallic parts. Effects such as the generation of harmonics, increase in reactive power absorption, vibration, and noise are not within the scope of this document.

Technical Considerations

The effects of half-cycle saturation on HV and EHV transformers, namely localized "hot spot" heating, are relatively well understood, but are difficult to quantify. A transformer GMD impact assessment must consider GIC amplitude, duration, and transformer physical characteristics such as design and condition (e.g., age, gas content, and moisture in the oil). A single threshold value of GIC cannot be justified as a "pass or fail" screening criterion where "fail" means that the transformer will suffer damage. A single threshold value of GIC only makes sense in the context where "fail" means that a more detailed study is required and that "pass" means that GIC in a particular transformer is so low that a detailed study is unnecessary. Such a threshold would have to be technically justifiable and sufficiently low to be considered a conservative value within the scope of the benchmark.

The following considerations should be taken into account when assessing the thermal susceptibility of a transformer to half-cycle saturation:

- In the absence of manufacturer specific information, use the temperature limits for safe transformer operation such as those suggested in the IEEE Std C57.91-2011 standard [1] for hot spot heating during short-term emergency operation. This standard does not suggest that exceeding these limits will result in transformer failure, but rather that it will result in additional aging of cellulose in the paper-oil insulation and the potential for the generation of gas bubbles in the bulk oil. Thus, from the point of view of evaluating

possible transformer damage due to increased hot spot heating, these thresholds can be considered conservative for a transformer in good operational condition.

- The worst case temperature rise for winding and metallic part (e.g., tie plate) heating should be estimated taking into consideration the construction characteristics of the transformer as they pertain to dc flux offset in the core (e.g., single-phase, shell, 5 and 3-leg three-phase construction).
- Bulk oil temperature due to ambient temperature and transformer loading must be added to the incremental temperature rise caused by hot spot heating. For planning purposes, maximum ambient and loading temperature should be used unless there is a technically justified reason to do otherwise.
- The time series or "waveshape" of the reference GMD event in terms of peak amplitude, duration, and frequency of the geoelectric field has an important effect on hot spot heating. Winding and metallic part hot spot heating have different thermal time constants, and their temperature rise will be different if the GIC currents are sustained for 2, 10, or 30 minutes for a given GIC peak amplitude.
- The "effective" GIC in autotransformers (reflecting the different GIC ampere-turns in the common and the series windings) must be used in the assessment. The effective current $I_{dc,eq}$ in an autotransformer is defined by [2].

$$I_{dc,eq} = I_H + (I_N/3 - I_H)V_X/V_H \quad (1)$$

where

I_H is the dc current in the high voltage winding;
I_N is the neutral dc current;
V_H is the rms rated voltage at HV terminals;
V_X is the rms rated voltage at the LV terminals.

Transformer Thermal Impact Assessment Process

A simplified thermal assessment may be based on Table 2 from the "Screening Criterion for Transformer Thermal Impact Assessment" white paper [7]. This table, shown as Table 1 below, provides the peak metallic hot spot temperatures that can be reached using conservative thermal models. To use Table 1, one must select the bulk oil temperature and the threshold for metallic hot spot heating, for instance, from reference [1] after allowing for possible de-rating due to transformer condition. If the effective GIC results in higher than threshold temperatures, then the use of a detailed thermal assessment as described below should be carried out.

Table 1: Upper Bound of Peak Metallic Hot Spot Temperatures Calculated Using the Benchmark GMD Event

Effective GIC (A/phase)	Metallic hot spot Temperature (°C)	Effective GIC(A/phase)	Metallic hot spot Temperature (°C)
0	80	100	182
10	107	110	186
20	128	120	190
30	139	130	193
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50	157	150	213
60	169	160	221
70	170	170	230
75	172	180	234
80	175	190	241
90	179	200	247

Two different ways to carry out a detailed thermal impact assessment are discussed below. In addition, other approaches and models approved by international standard-setting organizations such as the Institute of Electrical and Electronic Engineers (IEEE)[1] or International Council on Large Electric Systems (CIGRE) may also provide technically justified methods for performing thermal assessments. All thermal assessment methods should be demonstrably equivalent to assessments that use the benchmark GMD event.

1. Transformer manufacturer GIC capability curves. These curves relate permissible peak GIC (obtained by the user from a steady-state GIC calculation) and loading, for a specific transformer. An example of manufacturer capability curves is provided in **Figure 2**. Presentation details vary between manufacturers, and limited information is available regarding the assumptions used to generate these curves, in particular, the assumed waveshape or duration of the effective GIC. Some manufacturers assume that the waveshape of the GIC in the transformer windings is a square pulse of 2, 10, or 30 minutes in duration. In the case of the transformer capability curve shown in **Figure 2** [3], a square pulse of 900 A/phase with a duration of 2 minutes would cause the Flitch plate hot spot to reach a temperature of 180 °C at full load. While GIC capability curves are relatively simple to use, an amount of engineering judgment is necessary to ascertain which portion of a GIC waveshape is equivalent to, for example, a 2 minute pulse. Also, manufacturers generally maintain that in

[1] For instance, IEEE Std C57.163-2015 Guide for Establishing Power Transformer Capability while under Geomagnetic Disturbances

the absence of transformer standards defining thermal duty due to GIC, such capability curves must be developed for every transformer design and vintage.

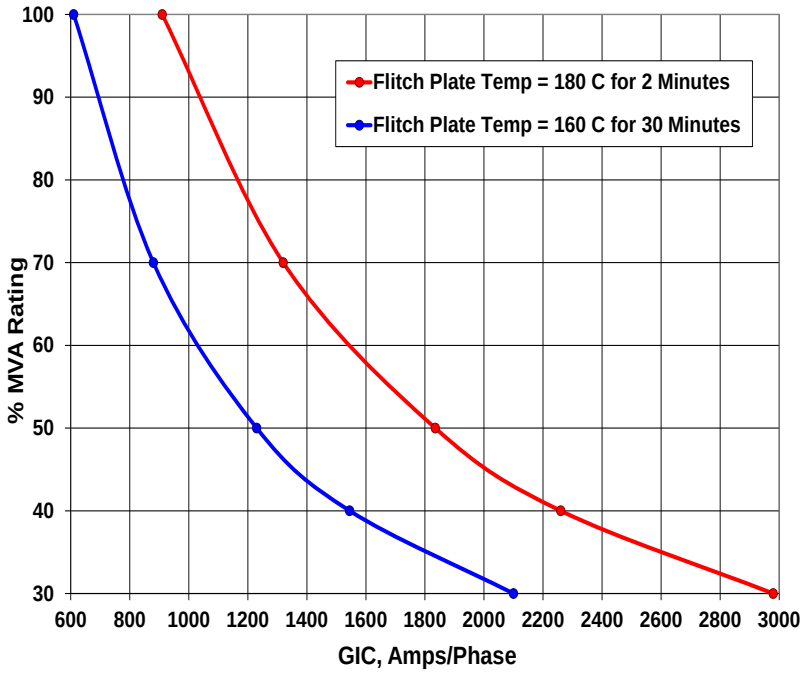


Figure 2: Sample GIC Manufacturer Capability Curve of a Large Single-Phase Transformer Design using the Flitch Plate Temperature Criteria [3]

2. Thermal response simulation[2]. The input to this type of simulation is the time series or waveshape of effective GIC flowing through a transformer (taking into account the actual configuration of the system), and the result of the simulation is the hot spot temperature (winding or metallic part) time sequence for a given transformer. An example of GIC input and hotspot temperature time series values from [4] are shown in **Figure 3**. The hot spot thermal transfer functions can be obtained from measurements or calculations provided by transformer manufacturers. Conservative default values can be used (e.g. those provided in [4]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std C57.91 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

[2] Technical details of this methodology can be found in [4].

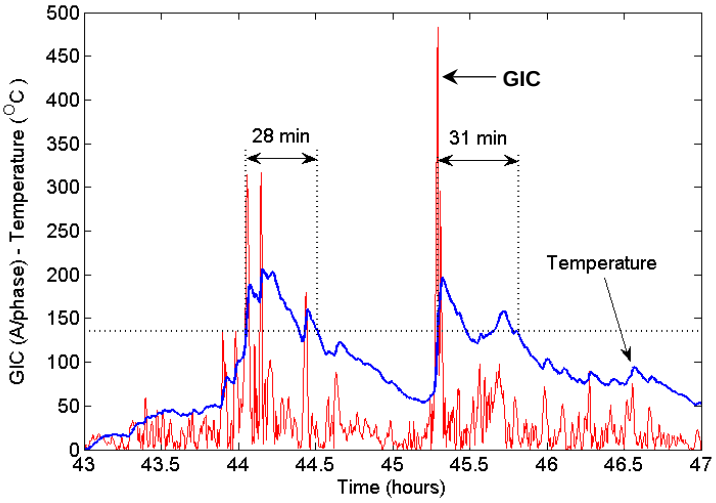


Figure 3: Sample Tie Plate Temperature Calculation
Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [4]

It is important to reiterate that the characteristics of the time sequence or "waveshape" are very important in the assessment of the thermal impact of GIC on transformers. Transformer hot spot heating is not instantaneous. The thermal time constants of transformer windings and metallic parts are typically on the order of minutes to tens of minutes; therefore, hot spot temperatures are heavily dependent on GIC history and rise time, amplitude and duration of GIC in the transformer windings, bulk oil temperature due to loading, ambient temperature and cooling mode.

Calculation of the GIC Waveshape for a Transformer

The following procedure can be used to generate time series GIC data, i.e. GIC(t), using a software program capable of computing GIC in the steady-state. The steps are as follows:

1. Calculate contribution of GIC due to eastward and northward geoelectric fields for the transformer under consideration;
2. Scale the GIC contribution according to the reference geoelectric field time series to produce the GIC time series for the transformer under consideration.

Most available GIC–capable software packages can calculate GIC in steady-state in a transformer assuming a uniform eastward geoelectric field of 1 V/km (GIC_E) while the northward geoelectric field is zero. Similarly, GIC_N can be obtained for a uniform northward geoelectric field of 1 V/km while the eastward geoelectric field is zero. GIC_E and GIC_N are the normalized GIC contributions for the transformer under consideration.

If the earth conductivity is assumed to be uniform (or laterally uniform) in the transmission system of interest, then the transformer GIC (in A/phase) for any value of $E_E(t)$ and $E_N(t)$ can be calculated using (2) [2].

$$GIC(t) = \left|E(t)\right| \cdot \left\{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\right\} \quad (2)$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \quad (3)$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \quad (4)$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \quad (5)$$

GIC_N is the effective GIC due to a northward geoelectric field of 1 V/km, and GIC_E is the effective GIC due to an eastward geoelectric field of 1 V/km. The units for GIC_N and GIC_E are A/phase/V/km)

The geoelectric field time series $E_N(t)$ and $E_E(t)$ is obtained, for instance, from the reference geomagnetic field time series [5] after the appropriate geomagnetic latitude scaling factor α is applied[3]. The reference geoelectric field time series is calculated using the reference earth model. When using this geoelectric field time series where a different earth model is applicable, it should be scaled with the conductivity scaling factor β[4]. Alternatively, the geoelectric field can be calculated from the reference geomagnetic field time series after the appropriate geomagnetic latitude scaling factor α is applied and the appropriate earth model is used. In such case, the conductivity scaling factor β is not applied because it is already accounted for by the use of the appropriate earth model.

Applying (5) to each point in $E_N(t)$ and $E_E(t)$ results in GIC(t).

GIC(t) Calculation Example

Let us assume that from the steady-state solution, the effective GIC in this transformer is GIC_E = -20 A/phase if E_N=0, E_E=1 V/km and GIC_N = 26 A/phase if E_N=1 V/km, E_E=0. Let us also assume the geomagnetic field time series corresponds to a geomagnetic latitude where α = 1 and that the earth conductivity corresponds to the reference earth model in [5]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore:

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \text{ (A/phase)} \quad (6)$$

$$GIC(t) = -E_E(t) \cdot 20 + \cdot E_N(t) \cdot 26 \text{ (A/phase)} \quad (7)$$

The resulting GIC waveshape GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

[3] The geomagnetic factor α is described in [2] and is used to scale the geomagnetic field according to geomagnetic latitude. The lower the geomagnetic latitude (closer to the equator), the lower the amplitude of the geomagnetic field.

[4] The conductivity scaling factor β is described in [2], and is used to scale the geoelectric field according to the conductivity of different physiographic regions. Lower conductivity results in higher β scaling factors.

It should be emphasized that even for the same reference event, the GIC(t) waveshape in every transformer will be different, depending on the location within the system and the number and orientation of the circuits connecting to the transformer station. Assuming a single generic GIC(t) waveshape to test all transformers is incorrect.

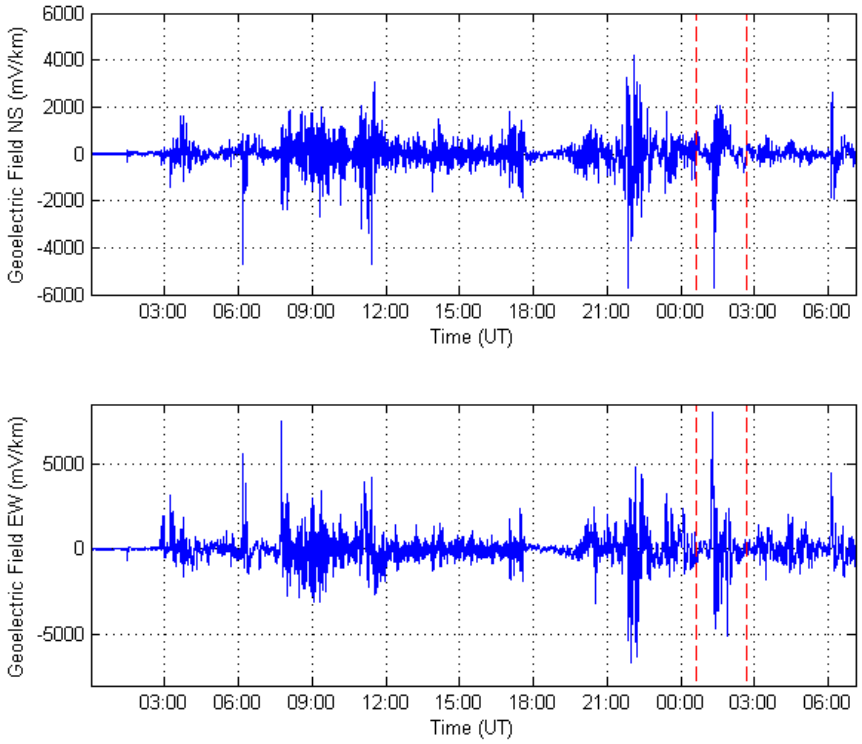


Figure 4: Calculated Geoelectric Field $E_N(t)$ and $E_E(t)$ Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model). Zoom area for subsequent graphs is highlighted. Dashed lines approximately show the close-up area for subsequent Figures.

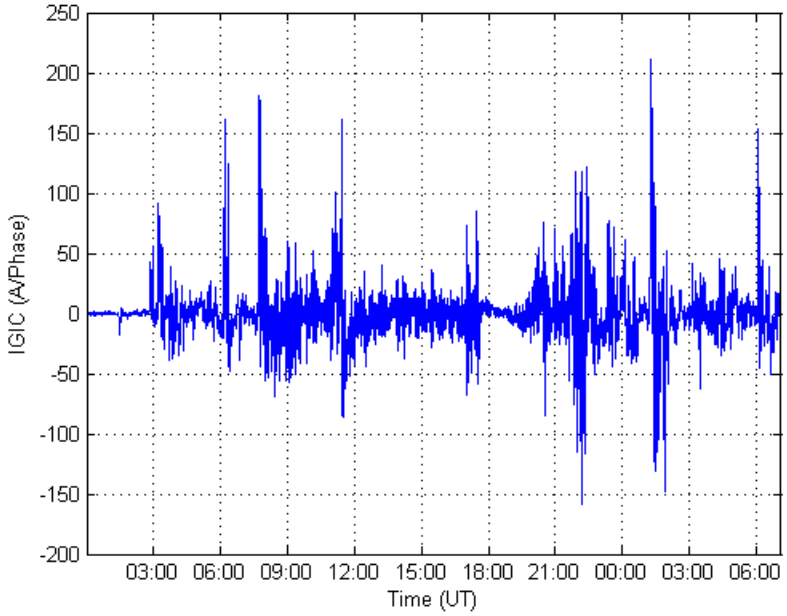


Figure 5: Calculated GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

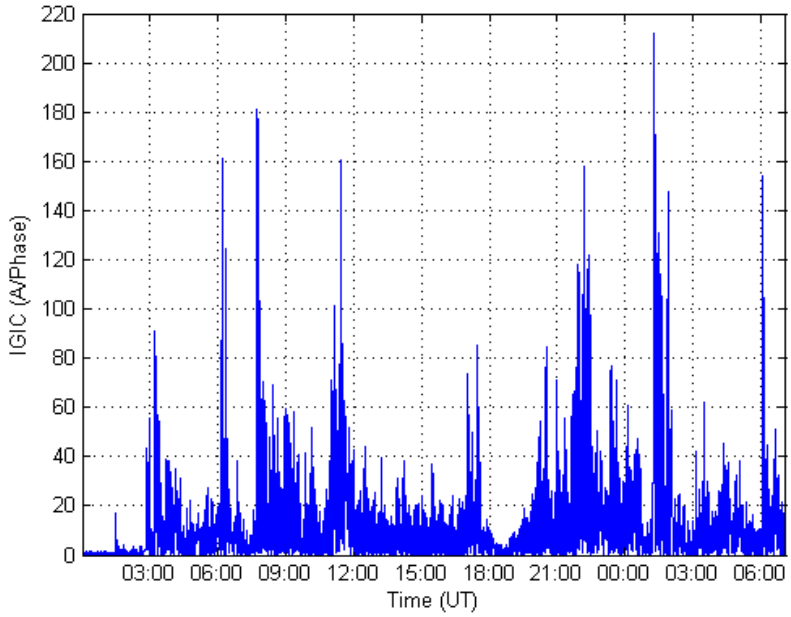


Figure 6: Calculated Magnitude of GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

Transformer Thermal Assessment Examples

There are two basic ways to carry out a transformer thermal analysis once the GIC time series GIC(t) is known for a given transformer: 1) calculating the thermal response as a function of time; and 2) using manufacturer's capability curves.

Example 1: Calculating thermal response as a function of time using a thermal response tool

The thermal step response of the transformer can be obtained for both winding and metallic part hot spots from: 1) measurements; 2) manufacturer's calculations; or 3) generic published values. **Figure 7** shows the measured metallic hot spot thermal response to a dc step of 16.67 A/phase of the top yoke clamp from [6] that will be used in this example. **Figure 8** shows the measured incremental temperature rise (asymptotic response) of the same hot spot to long duration GIC steps.[5]

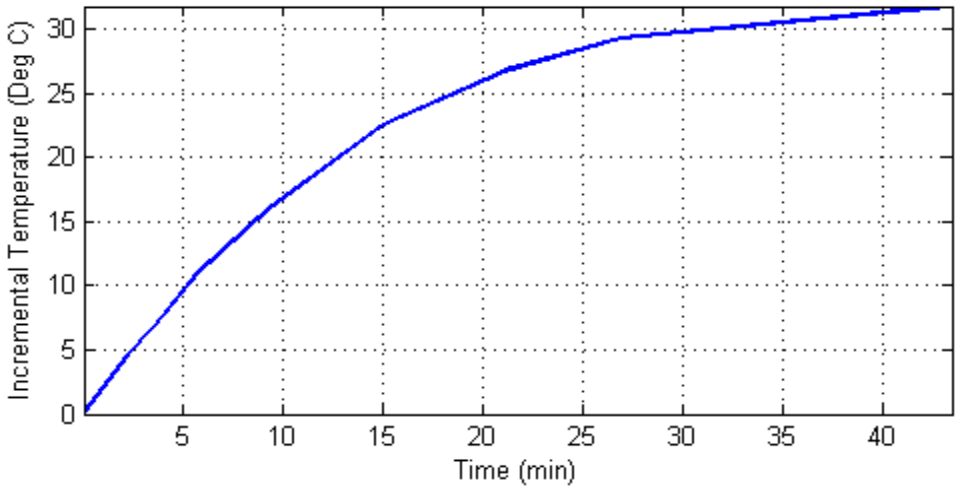


Figure 7: Thermal Step Response to a 16.67 Amperes per Phase dc Step
Metallic hot spot heating.

[5] Heating of bulk oil due to the hot spot temperature increase is not included in the asymptotic response because the time constant of bulk oil heating is at least an order of magnitude larger than the time constants of hot spot heating.

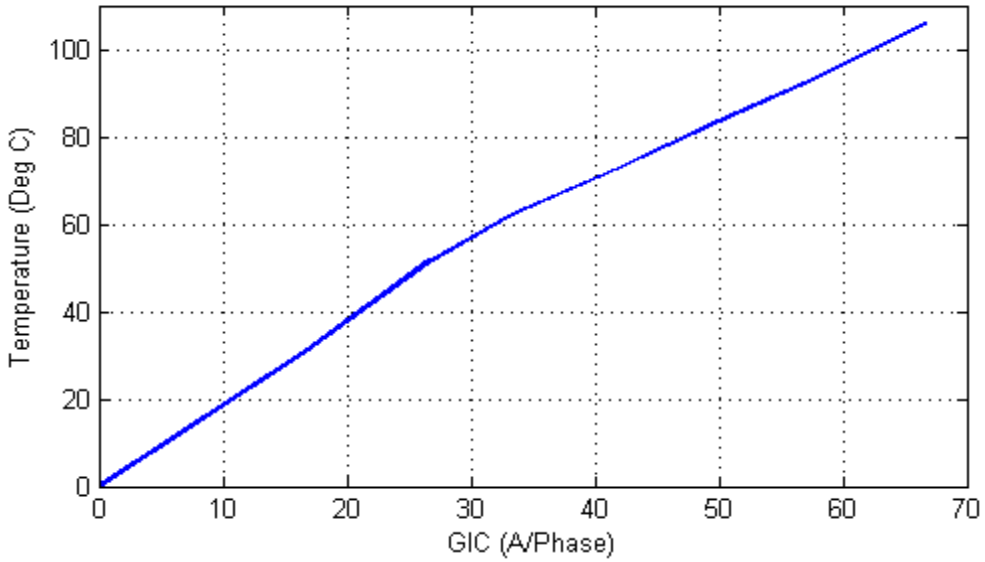


Figure 8: Asymptotic Thermal Step Response
Metallic hot spot heating.

The step response in **Figure 7** was obtained from the first GIC step of the tests carried out in [6]. The asymptotic thermal response in **Figure 8** was obtained from the final or near-final temperature values after each subsequent GIC step. **Figure 9** shows a comparison between measured temperatures and the calculated temperatures using the thermal response model used in the rest of this discussion.

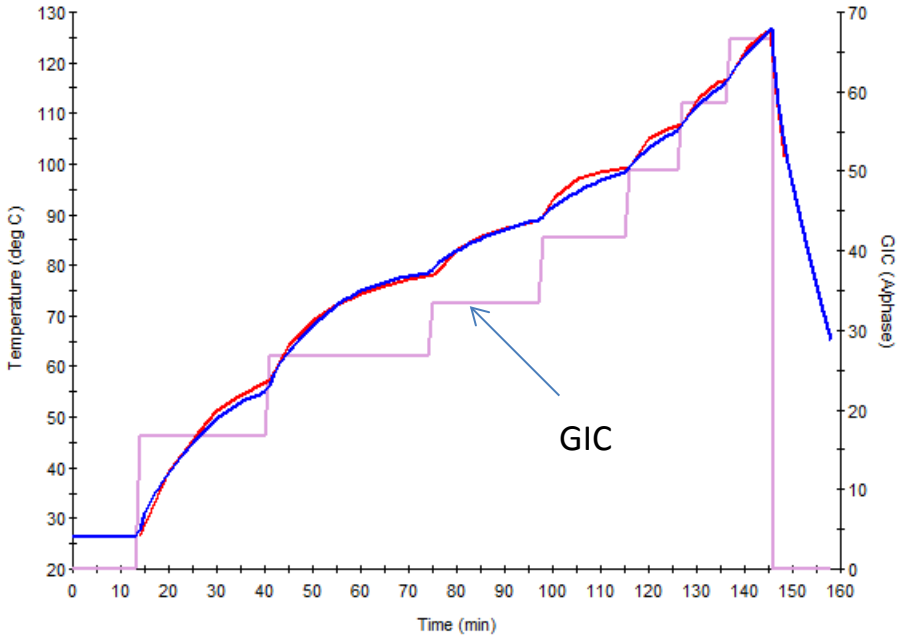


Figure 9: Comparison of measured temperatures (red trace) and simulation results (blue trace). Injected current is represented by the magenta trace.

To obtain the thermal response of the transformer to a GIC waveshape such as the one in **Figure 6**, a thermal response model is required. To create a thermal response model, the measured or manufacturer-calculated transformer thermal step responses (winding and metallic part) for various GIC levels are required. The GIC(t) time series or waveshape is then applied to the thermal model to obtain the incremental temperature rise as a function of time $\theta(t)$ for the GIC(t) waveshape. The total temperature is calculated by adding the oil temperature, for example, at full load.

Figure 10 illustrates the calculated GIC(t) and the corresponding hot spot temperature time series $\theta(t)$. **Figure 11** illustrates a close-up view of the peak transformer temperatures calculated in this example.

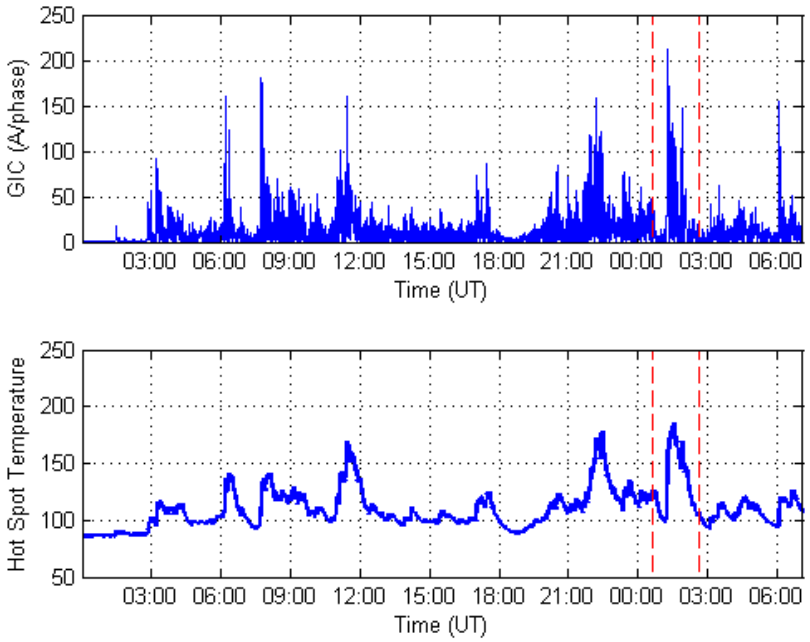


Figure 10: Magnitude of GIC(t) and Metallic Hot Spot Temperature $\theta(t)$ Assuming Full Load Oil Temperature of 85.3°C (40°C ambient). Dashed lines approximately show the close-up area for subsequent Figures.

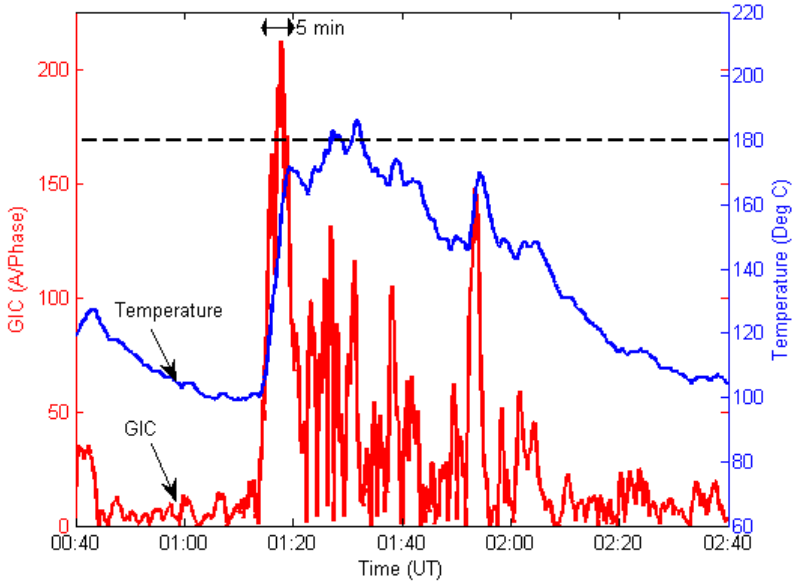


Figure 11: Close-up of Metallic Hot Spot Temperature Assuming a Full Load
(Blue trace is θ(t). Red trace is GIC(t))

In this example, the IEEE Std C57.91 emergency loading hot spot threshold of 200°C for metallic hot spot heating is not exceeded. Peak temperature is 186°C. The IEEE standard is silent as to whether the temperature can be higher than 200°C for less than 30 minutes. Manufacturers can provide guidance on individual transformer capability.

It is not unusual to use a lower temperature threshold of 180°C to account for calculation and data margins, as well as transformer age and condition. **Figure 11** shows that 180°C will be exceeded for 5 minutes.

At 75% loading, the initial temperature is 64.6 °C rather than 85.3 °C, and the hot spot temperature peak is 165°C, well below the 180°C threshold (see **Figure 12**).

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then the full load limits would be exceeded for approximately 22 minutes.

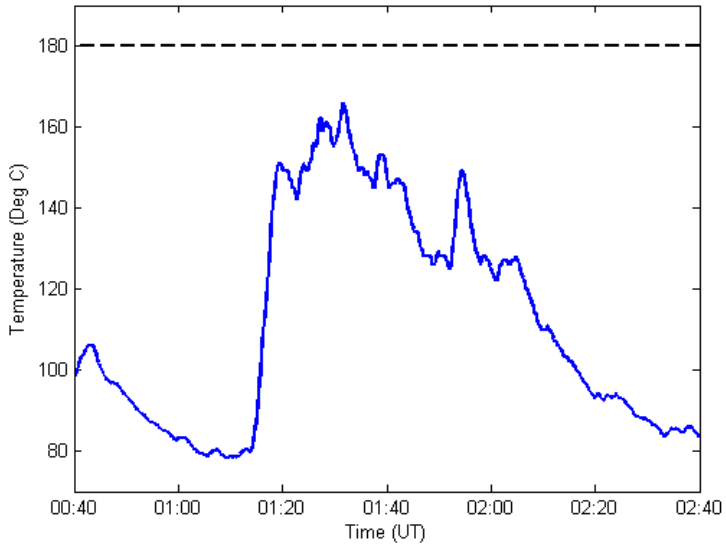


Figure 12: Close-up of Metallic Hot Spot Temperature Assuming a 75% Load
(Oil temperature of 64.5°C)

Example 2: Using a Manufacturer's Capability Curves

The capability curves used in this example are shown in **Figure 13**. To maintain consistency with the previous example, these particular capability curves have been reconstructed from the thermal step response shown in **Figures 7** and **8**, and the simplified loading curve shown in **Figure 14** (calculated using formulas from IEEE Std C57.91).

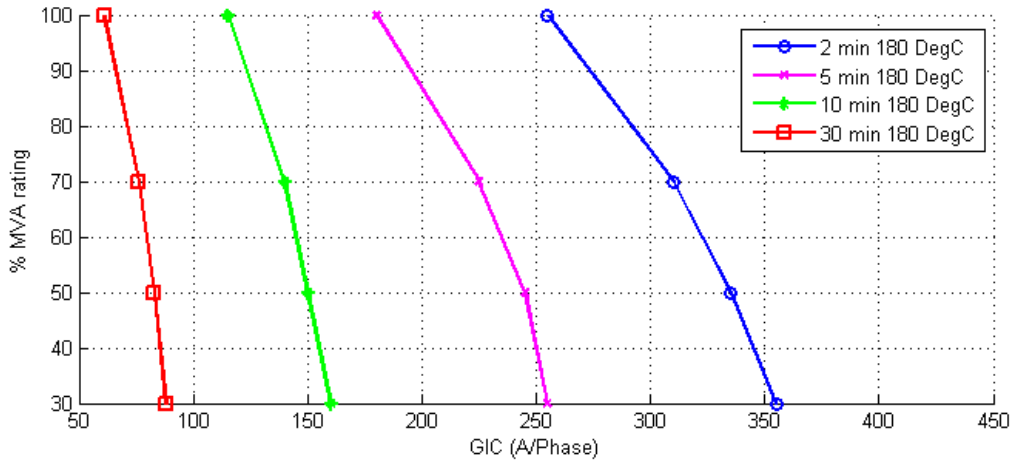


Figure 13: Capability Curve of a Transformer Based on the Thermal Response Shown in Figures 8 and 9.

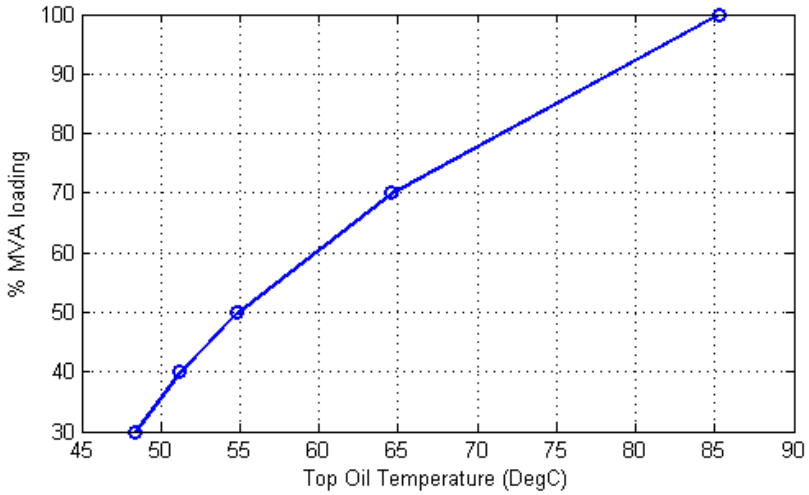


Figure 14: Simplified Loading Curve Assuming 40°C Ambient Temperature.

The basic notion behind the use of capability curves is to compare the calculated GIC in a transformer with the limits at different GIC pulse widths. A narrow GIC pulse has a higher limit than a longer duration or wider one. If the calculated GIC and assumed pulse width falls below the appropriate pulse width curve, then the transformer is within its capability.

To use these curves, it is necessary to estimate an equivalent square pulse that matches the waveshape of GIC(t), generally at a GIC(t) peak. **Figure 15** shows a close-up of the GIC near its highest peak superimposed to a 255 Amperes per phase, 2 minute pulse at 100% loading from **Figure 13**. Since a narrow 2-minute pulse is not representative of GIC(t) in this case, a 5 minute pulse with an amplitude of 180 A/phase at 100% loading has been superimposed on **Figure 16**. It should be noted that a 255 A/phase, 2 minute pulse is equivalent to a 180 A/phase 5 minute pulse from the point of view of transformer capability. Deciding what GIC pulse is equivalent to the portion of GIC(t) under consideration is a matter of engineering judgment.

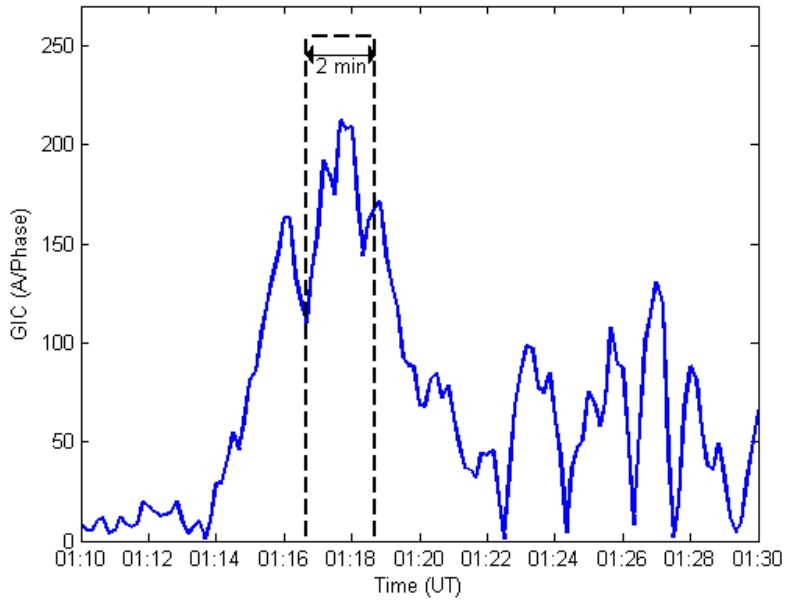


Figure 15: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load

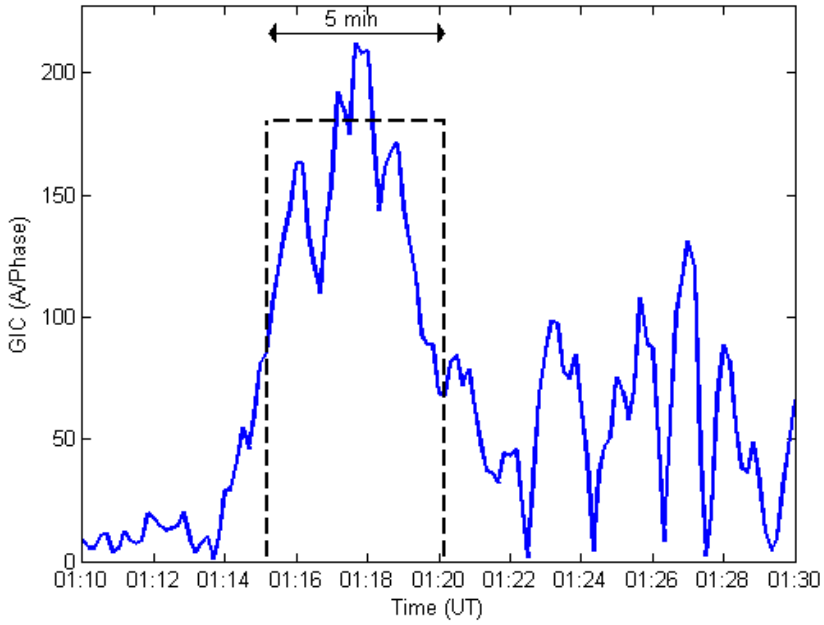


Figure 16: Close-up of GIC(t) and a Five Minute 180 A/phase GIC Pulse at Full Load

When using a capability curve, it should be understood that the curve is derived assuming that there is no hot spot heating due to prior GIC at the time the GIC pulse occurs (only an initial temperature due to loading). Therefore, in addition to estimating the equivalent pulse that matches GIC(t), prior hot spot heating must be accounted for. From

these considerations, it is unclear whether the capability curves would be exceeded at full load with a 180 °C threshold in this example.

At 70% loading, the two and five minute pulses from **Figure 13** would have amplitudes of 310 and 225 A/phase, respectively. The 5 minute pulse is illustrated in **Figure 17**. In this case, judgment is also required to assess if the GIC(t) is within the capability curve for 70% loading. In general, capability curves are easier to use when GIC(t) is substantially above, or clearly below the GIC thresholds for a given pulse duration.

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then a new set of capability curves would be required.

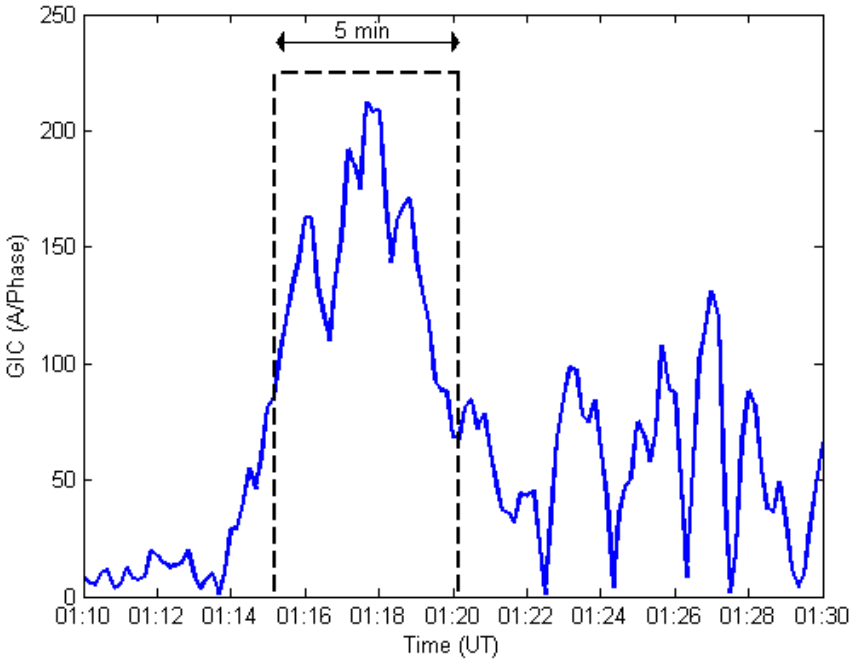


Figure 17: Close-up of GIC(t) and a 5 Minute 225 A/phase GIC Pulse Assuming 75% Load

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[6] Lahtinen, Matti. Jarmo Elovaara. "GIC occurrences and GIC test for 400 kV system transformer". IEEE Transactions on Power Delivery, Vol. 17, No. 2. April 2002.

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http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**

2. **Number:** IRO-002-~~4~~5

3. **Purpose:** To ~~Provide~~ provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.

4. **Applicability**

   4.1. Functional Entities

   ~~4.1.~~4.1.1 Reliability Coordinator

5. **Effective Date:**

   See Implementation Plan~~.~~

~~**6. Background:**~~

~~See the Project 2014~~2016 ~~03 01~~.

B. Requirements and Measures

Rationale for Requirements R1 and R2: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g. switches, routers, file servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Reliability Coordinator's (RC) primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. Requirement R2 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the RC's primary Control Center.

The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. The proposed requirements do not specify additional redundant data exchange infrastructure components solely to provide for redundancy during planned or unplanned outages of individual components.

Infrastructure that is not within the RC's primary Control Center is not addressed by the proposed requirement.

R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses~~, Real-time monitoring, and Real-time Assessments~~. *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning~~, Same-Day Operations, Real-time Operations~~]*

M1. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, a document that lists its data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its ~~operational~~ Operational Planning Analyses~~, Real-time monitoring, and Real-time Assessments~~.

R2. Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other~~a~~ documentation that lists its data exchange capabilities, ~~with~~including redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, as specified in the requirement.

Rationale for Requirement R3: The revised requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R3. Each Reliability Coordinator shall test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once

eachevery 90 calendar monthdays. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality,; or experienced an event that demonstrated the redundant functionality; and if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R3. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R2.R4. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M1.M4. Each Reliability Coordinator shall, have and provide upon request evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

R3.R5. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection SystemRemedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any -System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Special Protection SystemRemedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

R4.R6. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M6. The Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

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, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with ~~the NERC~~mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~**1.2. 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.~~

~~1.3.~~1.2. ~~Data~~ 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 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 retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and ~~R3~~R4 and Measures M1, M2, and ~~M3~~M4.

The Reliability Coordinator shall retain evidence for Requirement R3 and Measure M3 for the most recent 12 calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

The Reliability Coordinator shall keep data or evidence for Requirements R5 and R6 ~~R4~~ and Measures M5 and M6 ~~M4~~ for the current calendar year and one previous calendar year.

~~If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.~~

~~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.

~~1.4. Additional Compliance Information~~

~~None.~~

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with one applicable entity, or 5% or less of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more applicable entities or greater than 15% of the applicable entities, whichever is greater.
R2	N/A	N/A	The Reliability Coordinator had data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments, but did not have redundant and	The Reliability Coordinator did not have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments as specified in the requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, as specified in the requirement.	
R3	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant	The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Reliability Coordinator did not test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality ~~at least once each calendar month~~; OR The Reliability Coordinator tested its primary Control

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	exchange capabilities specified in Requirement R2 for redundant functionality at least once ~~each~~every 90 calendar ~~month~~days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	functionality at least once ~~each~~every 90 calendar ~~month~~days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	functionality at least once ~~each~~every 90 calendar ~~month~~days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once ~~each~~every 90 calendar ~~month~~days but, following an unsuccessful test, did not initiate action to restore the redundant functionality in more than 8 hours.
~~R2~~R4	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.
~~R3~~R5	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of ~~Special Protection~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~System~~Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
~~R4~~R6	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The Implementation Plan and other project documents can be found on the project page.~~None.~~

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 4, 2007	Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised to add missing measures and compliance elements
2	October 17, 2008	Adopted by NERC Board of Trustees	Deleted R2, M3 and associated compliance elements as conforming changes associated with approval of IRO-010-1. Revised as part of IROL Project
2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	FERC approval
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	VSLs revised
3	July 25, 2011	Revised under Project 2006-06	Revised

3	August 4, 2011	Approved by Board of Trustees	Retired R1-R8 under Project 2006-06.
4	November 13, 2014	Approved by Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved IRO-002-4. Docket No. RM15-16-000	
5	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of IRO-002-5, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of IRO-002-5, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of IRO-002-4 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

~~**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.~~

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for Requirements:

The data exchange elements of Requirements R1 and R2 from approved IRO-002-2 have been added back into proposed IRO-002-4 in order to ensure that there is no reliability gap. The ~~SDT~~Project 2014-03 SDT found no proposed requirements in the current project that covered the issue. Voice communication is covered in proposed COM-001-2 but data communications needs to remain in IRO-002-4 as it is not covered in proposed COM-001-2. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

Rationale for R2:

Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 (R6 in IRO-002-5) has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

Rationale for R4 (R6 in IRO-002-6):

The ~~R~~requirement ~~R4~~ ~~R6~~ was added back from approved IRO-002-2 as the Project 2014-03 SDT found no proposed requirements that covered the issues.

A. Introduction

1. **Title: Transmission Operations**

2. **Number: TOP-001-~~3~~4**

3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.

4. **Applicability:**

   4.1. Balancing Authority

   4.2. Transmission Operator

   4.3. Generator Operator

   4.4. Distribution Provider

5. **Effective Date:**

   See Implementation Plan~~.~~

~~**6. Background:**~~

~~See Project 2014-03 project page.~~

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and

provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings,

electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining System Operating Limit (SOL) exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4 (proposed IRO-002-5 Requirement R5), which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.

The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability are monitored. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. The facilities that are necessary for determining SOL exceedances should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis (OPA) required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

The non-BES facilities that the TOP is required to monitor are only those that are necessary for the TOP to determine SOL exceedances within its Transmission Operator Area. TOPs perform various analyses and studies as part of their functional obligations that could lead to identification of non-BES facilities that should be monitored for determining SOL exceedances. Examples include:

- OPA;
- Real-time Assessments (RTA);

- Analysis performed by the TOP as part of BES Exception processing for including a facility in the BES; and
- Analysis which may be specified in the RC's outage coordination process that leads to the identification of a non-BES facility that should be temporarily monitored for determining SOL exceedances.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its OPAs, Real-time monitoring, and RTAs. This includes non-BES data and external network data as deemed necessary by the TOP.

The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

R10. Each Transmission Operator shall perform the following ~~as necessary~~ for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. ~~Within its Transmission Operator Area, monitor~~ Monitor Facilities within its Transmission Operator Area; ~~and~~

10.2. Monitor the status of ~~Special Protection Systems~~Remedial Action Schemes within its Transmission Operator Area;

~~10.1.~~**10.3.** Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;~~and~~

10.4. ~~Outside its Transmission Operator Area, o~~Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

~~**10.2.** and the status of Special Protection Systems.~~

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized ~~status, voltages, and flow~~ data ~~for Facilities and the status of~~

~~Special Protection Systems~~ as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of ~~Special Protection System~~Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of ~~Special Protection System~~Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_V. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL T_V. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Rationale for Requirements R19 and R20: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g. switches, routers, file servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Transmission Operator's (TOP) primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. Requirement R20 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the TOP's primary Control Center.

The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. The proposed requirements do not specify additional redundant data exchange infrastructure components solely to provide for redundancy during planned or unplanned outages of individual components.

Infrastructure that is not within the TOP's primary Control Center is not addressed by the proposed requirement.

R19. Each Transmission Operator shall have data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning Analyses.~~the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area.~~ *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning~~, Same-Day Operations, Real-time Operations~~]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to ~~maintain reliability in its Transmission Operator Area~~perform its Operational Planning Analyses.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments.

[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order to perform its Real-time monitoring and Real-time Assessments as specified in the requirement.

Rationale for Requirement R21: The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R21. Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

Rationale for Requirements R22 and R23: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g. switches, routers, file servers, power supplies, and

network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Balancing Authority's (BA) primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. Requirement R23 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the BA's primary Control Center.

The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. The proposed requirements do not specify additional redundant data exchange infrastructure components solely to provide for redundancy during planned or unplanned outages of individual components.

Infrastructure that is not within the BA's primary Control Center is not addressed by the proposed requirement.

~~R20.~~R22. Each Balancing Authority shall have data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to develop its Operating Plan for next-day operations.~~maintain reliability in its Balancing Authority Area.~~ *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning~~, Same-Day Operations, Real-time Operations~~]*

M2~~0~~. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to ~~maintain reliability in its Balancing Authority Area~~develop its Operating Plan for next-day operations.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary

Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order to perform its Real-time monitoring and analysis functions as specified in the requirement.

Rationale for Requirement R24: The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R24. Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R24. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

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, 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 ~~the NERC~~ Reliability Standards in their respective jurisdictions.

~~1.2. 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.~~

~~1.3.~~1.2. ~~Data~~ 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 following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.~~

Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and ~~R15 through R20 and~~ Measure M1 through M11~~, and M15 through M20~~ for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ~~ninety~~ 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12.

~~and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14.~~

Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence ~~and~~ that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 for three calendar years.

Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R20, and Measure M15

through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

Each Balancing Authority shall each keep data or evidence for each applicable Requirement R22 through R23, and Measure M22 through M23 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

~~If a Balancing Authority, Transmission Operator, Generator Operator, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period 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.

~~1.4. Additional Compliance Information~~

~~None.~~

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities,	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Emergency on respective Balancing Authority Areas.	resulted in, an Emergency on respective Balancing Authority Areas.
R9	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				assessment capabilities, or associated communication channels between the affected entities.
R10	The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.~~N/A~~	The Transmission Operator did not monitor, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1~~.~~ through 10.6. ~~OR,~~ ~~The Transmission Operator did not obtain and utilize one of the items listed in Requirement R10, Part 10.2.~~	The Transmission Operator did not monitor, obtain, or utilize three of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6~~ and did not obtain and utilize one of the items listed in Requirement R10, Part 10.2~~.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.~~Facilities and the status of Special Protection Systems within its Transmission Operator Area and did not obtain and utilize data deemed as necessary from outside its Transmission Operator Area.~~
R11	N/A	N/A	The Balancing Authority did not monitor the status of ~~Special Protection System~~Remedial Action Schemes that impact	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	support Interconnection frequency.
R12	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				channels between affected entities.
R18	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R20	N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments as specified in the Requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, as specified in the Requirement.	
R21	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Transmission Operator did not test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality; OR The Transmission Operator tested its primary Control Center data exchange

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.
~~R20~~R 22	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R23	N/A	N/A	The Balancing Authority had data exchange	The Balancing Authority did not have data exchange

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions, but did not have redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, as specified in the Requirement.	capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions as specified in the Requirement.
R24	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test;	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Balancing Authority did not test its primary Control Center data exchange capabilities specified in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	Requirement R23 for redundant functionality; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The ~~SDT~~Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is: http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	
4	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of TOP-001-4, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of TOP-001-4, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of TOP-001-3 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

~~**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 R3:

The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

Rationale for Requirement R10:

New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

Rationale for Requirement R13:

The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Rationale for Requirement R14:

The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

Rationale for Requirements R16 and R17:

In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:

Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

Rationale for Requirements R19 and R20 (R19, R20, R22, and R23 in TOP-001-4):

Added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2016-01 - Modifications to TOP and IRO Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for Reliability Standard requirements developed in Project 2016-01. 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.

Project 2016-01 Reliability Standards Requirements

The SDT developed new or revised requirements in IRO-002-5 and TOP-001-4 to address reliability objectives outlined in the project Standard Authorization Request (SAR). The VRF and VSL justification for these new and revised requirements is described below. VRF and VSL justification for requirements that were not modified in Project 2016-01 can be found on the Project 2014-03 Project Page.

VRF Justification

VRF Justification for TOP-001-4 Requirement R10	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirement is not directly connected to an area identified in the Blackout Report.

VRF Justification for TOP-001-4 Requirement R10	
Proposed VRF	**High**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The proposed VRF is unchanged from approved TOP-001-3 Requirement R10. Additionally, the requirement is similar to approved IRO-002-4 Requirement R3 which applies to Reliability Coordinators and is assigned a High VRF.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Transmission Operator, could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement addresses a single reliability objective and has a single VRF.

VRF Justification for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements address data exchange capabilities for the Operations Planning time horizon, which are not the subject of the Blackout Report recommendations regarding data exchange. Data exchange capabilities for Same-day Operations and Real-time Operations are addressed in other requirements.

VRF Justification for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
Proposed VRF	**Medium**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirements address data exchange capabilities for the Operations Planning time horizon only, which is a significant change from approved IRO-002-4 Requirement R1 and TOP-001-3 Requirements R19 and R20 which apply to all operations time horizons. As proposed, the VRF will establish consistency among similar requirements in proposed IRO-002-5 and proposed TOP-001-4. Data exchange capabilities for Same-day Operations and Real-time Operations are addressed in other requirements.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for a Medium VRF. Failure to have data exchange capabilities necessary for performing Operational Planning Analysis or for developing an Operating Plan for next day operations could directly and adversely affect the electrical state or capability of the BES, or the ability to effectively control or restore the BES. However, this failure is unlikely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VRF Justification for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements address data exchange capabilities for the Same-day Operations and Real-time Operations time horizons. A High VSL is assigned to reflect the potential impact on the reliability of the BES consistent with the Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirements improve upon requirements for data exchange capabilities in approved IRO-002-4 and TOP-001-3, which are assigned a High VRF. As proposed, the VRF will maintain consistency among similar requirements in proposed IRO-002-5 and proposed TOP-001-4.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for a High VRF. Failure to have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the primary Control Center, for performing Real-time monitoring and analysis 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.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VRF Justification for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements are not directly connected to an area identified in the Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	These are new requirements. Approved COM-001-2.1 Requirement R9 requires periodic testing of Alternate Interpersonal Communications capability and is assigned a Medium VRF. As proposed, the VRF will maintain consistency among similar requirements in proposed IRO-002-5, proposed TOP-001-4, and approved COM-001-2.1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for Medium VRF. Failure to periodically test primary Control Center data exchange capabilities for redundant functionality could, under anticipated data exchange infrastructure failure, affect the ability to monitor and control the BES. However, failure to test primary Control Center data exchange capabilities for redundant functionality is not likely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VSL Justification

VSLs for TOP-001-4 Requirement R10			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize three of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.

VSL Justifications for TOP-001-4 Requirement R10	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	VSLs are comparable to approved TOP-001-3 Requirement R10.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for TOP-001-4 Requirement R10	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22			
Lower	**Moderate**	**High**	**Severe**
The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with one identified entity, or 5% or less of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with two identified entities, or more than 5% or less than or equal to 10% of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with three identified entities, or more than 10% or less than or equal to 15% of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with four or more identified entities or greater than 15% of the identified entities, whichever is greater.

VSL Justifications for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	VSLs are comparable to approved IRO-002-4 Requirement R1 and approved TOP-001-3 Requirements R19 and R20.
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 written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The applicable entity had data exchange capabilities with its (Reliability Coordinator, Balancing Authority, and/or Transmission Operator, as specified in the requirement) and identified entities for performing Real-time monitoring (and Real-time Assessments or analysis functions), but did not have redundant and diversely routed data exchange infrastructure	The applicable entity did not have data exchange capabilities with its (Reliability Coordinator, Balancing Authority, and/or Transmission Operator, as specified in the requirement) and identified entities for performing Real-time monitoring (and Real-time Assessments or analysis functions), as specified in the Requirement.

		within its primary Control Center, as specified in the Requirement.	

VSL Justifications for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no current compliance obligation for the proposed requirements.
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 written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24			
Lower	**Moderate**	**High**	**Severe**
The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality, but did so more than 180 calendar days since the previous test; OR The applicable entity did not test its primary Control Center data exchange capabilities for redundant functionality ~~at least once each calendar month~~; OR The applicable entity tested its primary Control Center data exchange capabilities for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.

VSL Justifications for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no current compliance obligation for the proposed requirements.
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 written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

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Implementation Plan

Project 2016-01 Modifications to TOP and IRO Standards
Reliability Standards IRO-002-5 and TOP-001-4

Applicable Standard(s)

- IRO-002-5 - Reliability Coordination - Monitoring and Analysis
- TOP-001-4 - Transmission Operations

Requested Retirement(s)

- IRO-002-4 - Reliability Coordination - Monitoring and Analysis
- TOP-001-3 - Transmission Operations

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Operator
- Generator Operator
- Distribution Provider

Background

On November 19, 2015, the Federal Energy Regulatory Commission (FERC) issued Order No. 817 approving nine revised or new TOP and IRO Reliability Standards from Project 2014-03 that addressed previously-identified reliability issues and concerns. In approving the standards, FERC also directed development of modifications to TOP and IRO standards to address specific concerns related to: (i) Transmission Operator monitoring of some non-Bulk Electric System (non-BES) elements needed for reliable operations, and (ii) redundancy in data exchange capabilities used by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable operations.

General Considerations

The three-month implementation period for IRO-002-5 provides Reliability Coordinators with time to establish and document data exchange capabilities that are redundant and diversely routed, and to implement testing processes and procedures for redundant functionality. The proposed implementation plan presumes that IRO-002-4 is effective, or will become effective, on or before the effective date of IRO-002-5.

The 12-month implementation period for TOP-001-~~3~~ 4 provides Transmission Operators (TOP) with time to revise and distribute data specifications required by TOP-003-3 Requirement R1 to include non-BES data identified by the TOP, and receive data from entities responsible for providing the data as required by TOP-003-3 Requirement R5. The implementation period also provides TOPs and Balancing Authorities (BAs) with time to establish and document data exchange capabilities that are redundant and diversely routed, and to implement testing processes and procedures for redundant functionality.

Effective Date

IRO-002-5
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 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 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

TOP-001-4
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 12 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 12 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

IRO-002-4
Reliability Standard IRO-002-4 shall be retired immediately prior to the effective date of IRO-002-5 in the particular jurisdiction in which the revised standard is becoming effective.

TOP-001-3
Reliability Standard TOP-001-3 shall be retired immediately prior to the effective date of TOP-001-4 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance of Periodic Requirements

IRO-002-5
The initial test of primary Control Center data exchange capabilities specified in Requirement R3 must be completed within 90 calendar days of the effective date of IRO-002-5.

TOP-001-4
The initial test of primary Control Center data exchange capabilities specified in Requirements R21 and R24 must be completed within 90 calendar days of the effective date of TOP-001-4.

Order No. 817 Citation	Directive / Guidance	Resolution
P 35	Revise Reliability Standard TOP-001-3, Requirement R10 to require real-time monitoring of non-BES facilities.	The directive is addressed in proposed TOP-001-4 Requirement R10. Parts 10.3 and 10.6 cover non-BES facilities. ***Proposed TOP-001-4*** **R10.** Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: **10.1.** Monitor Facilities within its Transmission Operator Area; **10.2.** Monitor the status of Remedial Action Schemes within its Transmission Operator Area; **10.3.** Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator; **10.4.** Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator; **10.5.** Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and **10.6.** Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

Order No. 817 Citation	Directive / Guidance	Resolution
P 47	Modify Reliability Standards TOP-001-3, Requirements R19 and R20 to include the requirement that the data exchange capabilities of the transmission operators and balancing authorities require redundancy and diverse routing. In addition, [the Commission directs] NERC to clarify that "redundant infrastructure" for system monitoring in Reliability Standards IRO-002-4, Requirement R4 is equivalent to redundant and diversely routed data exchange capabilities.	Proposed TOP-001-4 Requirements R20 and R23 address the directive for Transmission Operators (TOP) and Balancing Authorities (BA), respectively. For consistency, the Standards Drafting Team (SDT) developed proposed IRO-002-5 Requirement R2 to address the directive for Reliability Coordinators (RCs) rather than develop a modification to IRO-002-4 Requirement R4. ***Proposed TOP-001-4*** **R20.** Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments. **R23.** Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and analysis functions. ***Proposed IRO-002-5*** **R2.** Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators,

Order No. 817 Citation	Directive / Guidance	Resolution
		and with other entities it deems necessary, for performing its Real-time monitoring and Real-time Assessments.
P 51	Develop a modification to the TOP and IRO standards that addresses a data exchange capability testing framework for the data exchange capabilities used in the primary control centers to test the alternate or less frequently used data exchange capabilities of the reliability coordinator, transmission operator and balancing authority.	The directive is addressed in proposed TOP-001-4 Requirements R21 and R24, and proposed IRO-002-5 Requirement R3. ***Proposed TOP-001-3*** **R21.** Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. **R24.** Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. ***Proposed IRO-002-5*** **R3.** Each Reliability Coordinator shall test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality.

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Standards Authorization Request Form

When completed, email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard(s):	Cyber Security - Supply Chain Controls		
Date Submitted:	September 28, 2016		
SAR Requester Information			
Name:	Corey Sellers		
Organization:	Southern Company / Chair, SAR and Standards Drafting Team		
Telephone:	205-257-7531	E-mail:	mcseller@southernco.com
SAR Type (Check as many as applicable)			
☒ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Purpose (Describe what the Standard action will achieve in support of Bulk Electric System reliability.):
The goal of this project is to establish forward-looking, objective-driven new or modified Reliability Standard(s) requiring entities to develop and implement a plan that includes security controls for supply chain management for industrial control system hardware, software, and computing and networking services that impact Bulk Electric System (BES) operations. The project will address the Federal Energy Regulatory Commission (FERC) directives contained in Order No. 829.
Industry Need (What is the industry problem this request is trying to solve?):
On July 21, 2016, FERC issued Order No. 829 directing NERC to develop a forward-looking, objective-driven new or modified Reliability Standard(s) that addresses supply chain risk management for industrial control system hardware, software, and computing and networking services associated with BES operations. The supply chains for information and communications technology and industrial control systems present risks to the BES by providing potential opportunities for the introduction of

SAR Information
cybersecurity vulnerabilities. The new or modified Reliability Standard(s) is intended to reduce the risk of a cybersecurity incident affecting the reliable operation of the Bulk-Power System.
Brief Description (Provide a paragraph that describes the scope of this Standard action.)
The Standards Drafting Team (SDT) shall develop new or modified Critical Infrastructure Protection (CIP) Standard(s) to require applicable entities to develop and implement a plan that includes security controls for supply chain management of industrial control system hardware, software, and computing and networking services that impact BES operations as described in Order No. 829. The work will include development of an Implementation Plan, Violation Risk Factors, Violation Severity Levels, and supporting documents, within the 12-month deadline established by FERC in Order No. 829.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the Standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the Standard action.)
The SDT shall address each of the Order No. 829 directives. The Reliability Standard(s) developed or revised in the project will require applicable entities to develop and implement a plan that addresses, at a minimum, the following four specific objectives as they relate to supply chain cybersecurity of the BES (Order No. 829 at P 45): 1. Software integrity and authenticity; 2. Vendor remote access; 3. Information system planning; and 4. Vendor risk management and procurement controls. The plan may apply different controls based on the criticality of different assets (Order No. 829 at P 44). Requirements developed by the SDT will be aimed at the protection of aspects of the supply chain that are within the control of responsible entities (Order No. 829 at P 10). The new or modified Reliability Standard will also require periodic reassessment of the applicable entity's selected controls by the applicable entity's CIP Senior Manager at least every 15 months (Order No. 829 at P 46). In addressing Objective 1 (Software integrity and authenticity), the SDT shall develop requirement(s) for applicable entities to address verification of: (1) the identity of the software publisher for all software and patches that are intended for use on BES Cyber Systems; and (2) the integrity of the software and patches before they are installed in the BES Cyber System. (Order No. 829 at P 48) In addressing Objective 2 (Vendor remote access), the SDT shall develop requirement(s) for applicable entities to address logging and controlling all third-party (i.e., vendor) initiated remote access sessions. The objective covers both user-initiated and machine-to-machine vendor remote access. Additionally,

SAR Information
applicable entities' controls must provide for rapidly disabling remote access sessions to mitigate a security event, if necessary. (Order No. 829 at P 51 and 52) In addressing Objective 3 (Information system planning), the SDT shall develop requirement(s) that address the applicable entities' CIP Senior Manager (or delegate) identification and documentation of risks for consideration by the applicable entity in proposed information system planning. (Order No. 829 at P 56) In addressing Objective 4 (Vendor risk management and procurement controls), the SDT shall develop requirement(s) for applicable entities to address the provision and verification of the following security concepts, at a minimum, in future contracts for industrial control system hardware, software, and computing and networking services associated with BES operations. (Order No. 829 at P 59) • Vendor security event notification processes; • Vendor personnel termination notification for employees with access to remote and onsite systems; • Product/services vulnerability disclosures, such as accounts that are able to bypass authentication or the presence of hardcoded passwords; • Coordinated incident response activities; and • Other related aspects of procurement that the SDT determines should be addressed for supply chain cyber security risk management as stated in Order No. 829. The SDT may, as an alternative, propose an equally efficient and effective means to meet the objectives in Order No. 829.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.

Reliability Functions		
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and Reactive Power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☐	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and Reactive Power supply and demand.

Reliability and Market Interface Principles	
☐	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.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A Reliability Standard shall not give any market participant an unfair competitive advantage.	YES
2. A Reliability Standard shall neither mandate nor prohibit any specific market structure.	YES
3. A Reliability Standard shall not preclude market solutions to achieving compliance with that Standard.	YES
4. A Reliability Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with Reliability Standards.	YES

Related Standards	
Standard No.	Explanation
CIP-002-5	Cyber Security - BES Cyber System Categorization. Specifies categorization of BES Cyber Systems and BES Cyber Assets to support appropriate protection against compromises that could lead to misoperation or instability in the BES.
CIP-003-6	Cyber Security - Security Management Controls. Establishes responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in BES
CIP-004-6	Cyber Security - Personnel & Training
CIP-005-5	Cyber Security - Electronic Security Perimeter(s)
CIP-007-6	Cyber Security - System Security Management

Related Standards	
CIP-010-2	Cyber Security - Configuration Change Management and Vulnerability Assessments
CIP-011-2	Cyber Security - Information Protection

Related SARs	
SAR ID	Explanation

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

Standard Development Timeline

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

Description of Current Draft

This draft of CIP-003-7 is addressing the directive issued by the Federal Energy Regulatory Commission (Commission) in paragraph 73 of Order No. 822 which reads:

> [T]he Commission concludes that a modification to the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6 is necessary to provide needed clarity to the definition and eliminate ambiguity surrounding the term "direct" as it is used in the proposed definition. Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule approving revisions to the cybersecurity Critical Infrastructure Protection (CIP) standards.

In this revision, the SDT revised Sections 2 and 3 of Attachments 1 and 2 in CIP-003-7 and removed the terms *Low Impact External Routable Connectivity* (LERC) and *Low Impact BES Cyber System Electronic Access Point* (LEAP). The modifications incorporate concepts and select language from the LERC definition into Attachment 1, Section 3 and focus the requirement on implementing electronic access controls for asset(s) containing low impact BES Cyber System(s). The SDT simplified Section 3 of Attachment 1 to require the Responsible Entity to permit only necessary inbound and outbound electronic access when using a routable protocol entering or leaving the asset between low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber system(s). When this communication is present, Responsible Entities are required to implement electronic access controls unless that communication meets the exclusion language (previously in the definition of LERC) contained in (iii) which reads: "not used for time-sensitive protection or control functions between intelligent electronic devices (e.g. communications using protocol IEC TR-61850-90-5 R-GOOSE)".

The defined term LEAP is no longer necessary because the SDT changed the requirement from requiring a LEAP to requiring electronic access controls. Additionally, since the SDT is removing the term LERC, the exclusion language that was previously in the definition of LERC was integrated into the Attachment 1, Section 3.1 requirement.

Because the proposed modifications to Reliability CIP-003-7 eliminate the need for the NERC Glossary terms: Low Impact External Routable Connectivity (LERC) and Low Impact BES Cyber System Electronic Access Point (LEAP), NERC is requesting these terms be retired in the associated Implementation Plan.

Additionally, the SDT:

- revised the associated Lower, Moderate, and High VSLs for Requirement R2 to complement the requirement revisions;
- corrected a mistake in the Severe VSL for Requirement R2;
- made non-substantive changes to the Moderate and High VSLs for Requirement R2 to align with the order of the requirement;
- removed repetitive text from Requirement R1, Part 1.2.3 to make it consistent with Parts 1.2.1 and 1.2.2;
- updated the Guidelines and Technical Basis section of the standard to reflect the revisions made to the Attachments; and
- made non-substantive errata changes throughout the standard such as replacing "ES-ISAC" with "E-ISAC".

Completed Actions	Date
Standard Authorization Request (SAR) approved	July 20, 2016
Draft 1 of CIP-003-7 posted for formal comment and initial ballot	July 21 – September 6, 2016
Draft 2 of CIP-003-7 posted for formal comment and additional ballot	October 21 – December 5, 2016

Anticipated Actions	Date
10-day final ballot	January, 2017
NERC Board of Trustees (BOT) adoption	February, 2017
Petition filed with FERC	March, 2017

A. Introduction

1. **Title:** Cyber Security — Security Management Controls

2. **Number:** CIP-003-~~6~~7

3. **Purpose:** To specify consistent and sustainable security management controls that establish responsibility and accountability to protect 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 contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

   4.1.1 Balancing Authority

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

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

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

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

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

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

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

   4.1.3 Generator Operator

   4.1.4 Generator Owner

4.1.5 Interchange Coordinator or Interchange Authority

4.1.6 Reliability Coordinator

4.1.7 Transmission Operator

4.1.8 Transmission Owner

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

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

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-003-~~6~~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 discrete Electronic Security Perimeters (ESPs).

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

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

5. Effective Dates:

See Implementation Plan for CIP-003-~~6~~7.

6. Background:

Standard CIP-003 exists as part of a suite of CIP Standards related to cyber security, which require the initial identification and categorization of BES Cyber Systems and require organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems.

The term policy refers to one or a collection of written documents that are used to communicate the Responsible Entities' management goals, objectives and expectations for how the Responsible Entity will protect its BES Cyber Systems. The use of policies also establishes an overall governance foundation for creating a culture of security and compliance with laws, regulations, and standards.

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 naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in its documented processes, but it must address the applicable requirements.

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

Similarly, the term program may refer to the organization's overall implementation of its policies, plans, and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Reliability 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, medium, and low impact BES Cyber Systems. For example, a single

cyber security awareness program could meet the requirements across multiple BES Cyber Systems.

Measures provide examples of evidence to show documentation and implementation of the requirement. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

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

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

B. Requirements and Measures

R1. Each Responsible Entity shall review and obtain CIP Senior Manager approval at least once every 15 calendar months for one or more documented cyber security policies that collectively address the following topics: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1 For its high impact and medium impact BES Cyber Systems, if any:

1.1.1. Personnel and training (CIP-004);

1.1.2. Electronic Security Perimeters (CIP-005) including Interactive Remote Access;

1.1.3. Physical security of BES Cyber Systems (CIP-006);

1.1.4. System security management (CIP-007);

1.1.5. Incident reporting and response planning (CIP-008);

1.1.6. Recovery plans for BES Cyber Systems (CIP-009);

1.1.7. Configuration change management and vulnerability assessments (CIP-010);

1.1.8. Information protection (CIP-011); and

1.1.9. Declaring and responding to CIP Exceptional Circumstances.

1.2 For its assets identified in CIP-002 containing low impact BES Cyber Systems, if any:

1.2.1. Cyber security awareness;

1.2.2. Physical security controls;

1.2.3. Electronic access controls ~~for Low Impact External Routable Connectivity (LERC) and Dial-up Connectivity~~; and

1.2.4. Cyber Security Incident response

M1. Examples of evidence may include, but are not limited to, policy documents; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager for each cyber security policy.

R2. Each Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems shall implement one or more documented cyber security plan(s) for its low impact BES Cyber Systems that include the sections in Attachment 1. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

Note: An inventory, list, or discrete identification of low impact BES Cyber Systems or their BES Cyber Assets is not required. Lists of authorized users are not required.

M2. Evidence shall include each of the documented cyber security plan(s) that collectively include each of the sections in Attachment 1 and additional evidence to demonstrate implementation of the cyber security plan(s). Additional examples of evidence per section are located in Attachment 2.

R3. Each Responsible Entity shall identify a CIP Senior Manager by name and document any change within 30 calendar days of the change. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. An example of evidence may include, but is not limited to, a dated and approved document from a high level official designating the name of the individual identified as the CIP Senior Manager.

R4. The Responsible Entity shall implement a documented process to delegate authority, unless no delegations are used. Where allowed by the CIP Standards, the CIP Senior Manager may delegate authority for specific actions to a delegate or delegates. These delegations shall be documented, including the name or title of the delegate, the specific actions delegated, and the date of the delegation; approved by the CIP Senior Manager; and updated within 30 days of any change to the delegation. Delegation changes do not need to be reinstated with a change to the delegator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. An example of evidence may include, but is not limited to, a dated document, approved by the CIP Senior Manager, listing individuals (by name or title) who are delegated the authority to approve or authorize specifically identified items.

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

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**Medium**	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address one of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 15 calendar months but did	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address two of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 16 calendar months but did	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address three of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address four or more of the nine topics required by R1. (R1.1) OR The Responsible Entity did not have any documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1. (R1.1) OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			complete this review in less than or equal to 16 calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of	complete this review in less than or equal to 17 calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 16 calendar months but did complete this approval in less than or equal to 17 calendar months of	calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact	The Responsible Entity did not complete its review of the one or more documented cyber security policies as required by R1 within 18 calendar months of the previous review. (R1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 18 calendar months of

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			the previous approval. (R1.1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address one of the four topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as	the previous approval. (R1.1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address two of the four topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as	BES Cyber Systems, but did not address three of the four topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its	the previous approval. (R1.1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address any of the four topics required by R1. (R1.2) OR The Responsible Entity did not have any documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by R1. (R1.2)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			required by Requirement R1 within 15 calendar months but did complete this review in less than or equal to 16 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 15 calendar months but did complete this	required by Requirement R1 within 16 calendar months but did complete this review in less than or equal to 17 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 16 calendar months but	assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1.2)	OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 18 calendar months of the previous approval. (R1.2)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			approval in less than or equal to 16 calendar months of the previous approval. (R1.2)	did complete this approval in less than or equal to 17 calendar months of the previous approval. (R1.2)		
R2	**Operations Planning**	**Lower**	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document cyber security awareness according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity implemented electronic access controls but failed to document its cyber security plan(s) for	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to reinforce cyber security practices at least once every 15 calendar months according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets	The Responsible Entity documented the physical access controls for its assets containing low impact BES Cyber Systems, but failed to implement the physical security controls according to Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for electronic access controls for its assets containing low impact BES Cyber Systems, but	The Responsible Entity failed to document ~~or~~and implement one or more cyber security plan(s) for its assets containing low impact BES Cyber Systems according to ~~CIP-003-6,~~ Requirement R2, Attachment 1. (R2)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			electronic access controls according to Requirement R2, Attachment 1, Section 3. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document one or more Cyber Security Incident response plans according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented one or more Cyber Security Incident	containing low impact BES Cyber Systems, but failed to document physical security controls according to Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document electronic access controls according to Requirement R2, Attachment 1, Section 3. (R2) OR The Responsible Entity documented	failed to permit only necessary inbound and outbound electronic access controls according to Requirement R2, Attachment 1, Section 3.1. (R2) OR The Responsible Entity documented one or more Cyber Security Incident response plans within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to test each Cyber Security Incident response plan(s) at least once every 36 calendar months according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 4. (R2) OR	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-67)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			response plans within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to update each Cyber Security Incident response plan(s) within 180 days according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 4. (R2)	its cyber security plan(s) for electronic access controls but failed to implement authentication for all Dial-up Connectivity that provides access to low impact BES Cyber System(s), per Cyber Asset capability according to Requirement R2, Attachment 1, Section 3.2 (R2) OR The Responsible Entity documented one or more incident response plans within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to include the process for identification,	The Responsible Entity documented the determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident, but failed to notify the Electricity ~~Sector~~ Information Sharing and Analysis Center (~~ES~~E-ISAC) according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 4. (R2) ~~OR~~ ~~The Responsible Entity documented and implemented electronic access controls for LERC, but failed to implement a LEAP or permit inbound and outbound access according to CIP-003-6, Requirement R2,~~	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				classification, and response to Cyber Security Incidents according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 4. (R2) ~~-~~OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document the determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity ~~Sector~~ Information Sharing and Analysis Center	~~Attachment 1, Section 3.~~ ~~(R2)~~ ~~OR~~ ~~The Responsible Entity documented and implemented electronic access controls for its assets containing low impact BES Cyber Systems, but failed to document and implement authentication of all Dial-up Connectivity, if any, that provides access to low impact BES Cyber Systems according to CIP-003-6, Requirement R2, Attachment 1, Section 3. (R2)~~ ~~OR~~ ~~The Responsible Entity documented the physical access controls for its assets containing low impact BES Cyber~~	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-67)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				(ESE-ISAC) according to CIP-003-6, Requirement R2, Attachment 1, Section 4. OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document physical security controls according to CIP-003-6, Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low	Systems, but failed to implement the physical security controls according to CIP-003-6, Requirement R2, Attachment 1, Section 2. (R2)	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~impact BES Cyber Systems, but failed to document electronic access controls according to CIP-003-6, Requirement R2, Attachment 1, Section 3.~~ ~~(R2)~~		
R3	**Operations Planning**	**Medium**	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 30 calendar days but did document this change in less than 40 calendar days of the change. (R3)	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 40 calendar days but did document this change in less than 50 calendar days of the change. (R3)	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 50 calendar days but did document this change in less than 60 calendar days of the change. (R3)	The Responsible Entity has not identified, by name, a CIP Senior Manager. OR The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 60 calendar

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						days of the change. (R3)
R4	**Operations Planning**	**Lower**	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 30 calendar days but did document this change in less than 40 calendar days of the change. (R4)	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 40 calendar days but did document this change in less than 50 calendar days of the change. (R4)	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 50 calendar days but did document this change in less than 60 calendar days of the change. (R4)	The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, but does not have a process to delegate actions from the CIP Senior Manager. (R4) OR The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 60 calendar days of the change. (R4)

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.	
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-003-5.	
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

Version	Date	Action	Change Tracking
			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-003-6. Docket No. RM15-14-000	
7	TBD	Adopted by the NERC Board of Trustees.	Revised to address FERC Order 822 directive regarding definition of LERC.

Attachment 1

Required Sections for Cyber Security Plan(s) for Assets Containing Low Impact BES Cyber Systems

Responsible Entities shall include each of the sections provided below in the cyber security plan(s) required under Requirement R2.

Responsible Entities with multiple-impact BES Cyber Systems ratings can utilize policies, procedures, and processes for their high or medium impact BES Cyber Systems to fulfill the sections for the development of low impact cyber security plan(s). Each Responsible Entity can develop a cyber security plan(s) either by individual asset or groups of assets.

Section 1. Cyber Security Awareness:~~-~~ Each Responsible Entity shall reinforce, at least once every 15 calendar months, cyber security practices (which may include associated physical security practices).

Rationale for Modifications to Sections 2 and 3 of Attachment 1 (Requirement R2):

Requirement R2 mandates that entities develop and implement one or more cyber security plan(s) to meet specific security control objectives for assets containing low impact BES Cyber System(s). In Paragraph 73 of FERC Order No. 822, the Commission directed NERC to modify "…the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6…to provide needed clarity to the definition and eliminate ambiguity surrounding the term "direct" as it is used in the proposed definition…within one year of the effective date of this Final Rule.

The revisions to Section 3 incorporate select language from the LERC definition into Attachment 1 and focus the requirement on implementing electronic access controls for asset(s) containing low impact BES Cyber System(s). This change requires the Responsible Entity to permit only necessary inbound and outbound electronic access when using a routable protocol entering or leaving the asset between low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber system(s). When this communication is present, Responsible Entities are required to implement electronic access controls unless that communication meets the exclusion language (previously in the definition of LERC) contained in (iii) which reads: "not used for time-sensitive protection or control functions between intelligent electronic devices (e.g. communications using protocol IEC TR-61850-90-5 R-GOOSE)".

The revisions to Section 2 of Attachment 1 complement the revisions to Section 3; consequently, the requirement now mandates the Responsible Entity control physical access to "the Cyber Asset(s), as specified by the Responsible Entity, that provide electronic access control(s) implemented for Section 3.1, if any." The

focus on electronic access controls rather than on the Low Impact BES Cyber System Electronic Access Points (LEAPs) eliminates the need for LEAPs.

Given these revisions to Sections 2 and 3, the NERC Glossary terms: Low Impact External Routable Connectivity (LERC) and Low Impact BES Cyber System Electronic Access Point (LEAP) will be retired.

Section 2. Physical Security Controls: Each Responsible Entity shall control physical access, based on need as determined by the Responsible Entity, to (1) the asset or the locations of the low impact BES Cyber Systems within the asset ~~and (2) the Low Impact BES Cyber System Electronic Access Points (LEAPs),~~, and (2) the Cyber Asset(s), as specified by the Responsible Entity, that provide electronic access control(s) implemented for Section 3.1, if any.

~~**Section 3.**~~ Electronic Access Controls: ~~Each~~For each asset containing low impact BES Cyber System(s) identified pursuant to CIP-002, the Responsible Entity shall~~:~~

Section 3. ~~For LERC, if any,~~ implement ~~a LEAP to permit~~electronic access controls to:

3.1 Permit only necessary inbound and outbound ~~bi-directional~~electronic access as determined by the Responsible Entity for any communications that are:

i. between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s);

~~i.~~ii. using a routable protocol ~~access; and~~when entering or leaving the asset containing the low impact BES Cyber System(s); and,

iii. ~~Implement authentication for~~not used for time-sensitive protection or control functions between intelligent electronic devices (e.g. communications using protocol IEC TR-61850-90-5 R-GOOSE).

3.2 Authenticate all Dial-up Connectivity, if any, that provides access to low impact BES Cyber System(s), per Cyber Asset capability.

Section 4. Cyber Security Incident Response: Each Responsible Entity shall have one or more Cyber Security Incident response plan(s), either by asset or group of assets, which shall include:

4.1 Identification, classification, and response to Cyber Security Incidents;

4.2 Determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity ~~Sector~~ Information Sharing and Analysis Center (~~ES~~E-ISAC), unless prohibited by law;

4.3 Identification of the roles and responsibilities for Cyber Security Incident response by groups or individuals;

4.4 Incident handling for Cyber Security Incidents;

4.5 Testing the Cyber Security Incident response plan(s) at least once every 36 calendar months by: (1) responding to an actual Reportable Cyber Security Incident; (2) using a drill or tabletop exercise of a Reportable Cyber Security Incident; or (3) using an operational exercise of a Reportable Cyber Security Incident; and

4.6 Updating the Cyber Security Incident response plan(s), if needed, within 180 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident.

~~CIP-003-6~~ Attachment 2

Examples of Evidence for Cyber Security Plan(s) for Assets Containing Low Impact BES Cyber Systems

Section 1. Cyber Security Awareness: An example of evidence for Section 1 may include, but is not limited to, documentation that the reinforcement of cyber security practices occurred at least once every 15 calendar months. The evidence could be documentation through one or more of the following methods:

- Direct communications (for example, e-mails, memos, or computer-based training);
- Indirect communications (for example, posters, intranet, or brochures); or
- Management support and reinforcement (for example, presentations or meetings).

Section 2. Physical Security Controls: Examples of evidence for Section 2 may include, but are not limited to:

- Documentation of the selected access control(s) (e.g., card key, locks, perimeter controls), monitoring controls (e.g., alarm systems, human observation), or other operational, procedural, or technical physical security controls that control physical access to both:
  a. The asset, if any, or the locations of the low impact BES Cyber Systems within the asset; and
  b. The Cyber Asset specified by the Responsible Entity that provides electronic access controls implemented for Section 3.1, if any~~, containing a LEAP~~.

Section 3. Electronic Access Controls: Examples of evidence for Section 3 may include, but are not limited to:

1. ~~Documentation showing that inbound and outbound connections for any LEAP(s) are confined to only those the Responsible Entity deems necessary (e.g., by restricting IP addresses, ports, or services); and documentation~~Documentation, such as representative diagrams or lists of implemented electronic access controls (e.g., restricting IP addresses, ports, or services; implementing unidirectional gateways) showing that at each asset or group of assets containing low impact BES Cyber Systems, routable communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset is restricted by electronic access controls to permit only inbound and outbound electronic access that the Responsible Entity deems necessary, except where an entity provides rationale that communication is used for time-sensitive protection or control functions between intelligent electronic devices; and

~~1.~~2. Documentation of authentication for Dial-up Connectivity (e.g., dial out only to a preprogrammed number to deliver data, dial-back modems, modems

that must be remotely controlled by the control center or control room, or access control on the BES Cyber System).

Section 4. Cyber Security Incident Response: An example of evidence for Section 4 may include, but is not limited to, dated documentation, such as policies, procedures, or process documents of one or more Cyber Security Incident response plan(s) developed either by asset or group of assets that include the following processes:

1. to identify, classify, and respond to Cyber Security Incidents; to determine whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and for notifying the Electricity ~~Sector~~ Information Sharing and Analysis Center (~~ES~~E-ISAC);
2. to identify and document the roles and responsibilities for Cyber Security Incident response by groups or individuals (e.g., initiating, documenting, monitoring, reporting, etc.);
3. for incident handling of a Cyber Security Incident (e.g., containment, eradication, or recovery/incident resolution);
4. for testing the plan(s) along with the dated documentation that a test has been completed at least once every 36 calendar months; and
5. to update, as needed, Cyber Security Incident response plan(s) within 180 calendar days after completion of a test or actual Reportable Cyber Security Incident.

Guidelines and Technical Basis

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

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

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

Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. 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:

In developing policies in compliance with Requirement R1, the number of policies and their content should be guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a general information security program for the entire organization, or as components of specific programs. The Responsible Entity has the flexibility to develop a single comprehensive cyber security policy covering the required topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-~~6~~7, Requirement R1.

If a Responsible Entity has any high or medium impact BES Cyber Systems, the one or more cyber security policies must cover the nine subject matter areas required by CIP-003-~~6~~7, Requirement R1, Part 1.1. If a Responsible Entity has identified from CIP-002 any assets containing low impact BES Cyber Systems, the one or more cyber security policies must cover the four subject matter areas required by Requirement R1, Part 1.2.

Responsible Entities that have multiple-impact rated BES Cyber Systems are not required to create separate cyber security policies for high, medium, or low impact BES Cyber Systems. The Responsible Entities have the flexibility to develop policies that cover all three impact ratings.

Implementation of the cyber security policy is not specifically included in CIP-003-~~6~~7, Requirement R1 as it is envisioned that the implementation of this policy is evidenced through successful implementation of CIP-003 through CIP-011. However, Responsible Entities are encouraged not to limit the scope of their cyber security policies to only those requirements in NERC cyber security Reliability Standards, but to develop a holistic cyber security policy

appropriate for its organization. Elements of a policy that extend beyond the scope of NERC's cyber security Reliability Standards will not be considered candidates for potential violations although they will help demonstrate the organization's internal culture of compliance and posture towards cyber security.

For Part 1.1, the Responsible Entity should consider the following for each of the required topics in its one or more cyber security policies for medium and high impact BES Cyber Systems, if any:

1.1.1 Personnel and training (CIP-004)

- Organization position on acceptable background investigations
- Identification of possible disciplinary action for violating this policy
- Account management

1.1.2 Electronic Security Perimeters (CIP-005) including Interactive Remote Access

- Organization stance on use of wireless networks
- Identification of acceptable authentication methods
- Identification of trusted and untrusted resources
- Monitoring and logging of ingress and egress at Electronic Access Points
- Maintaining up-to-date anti-malware software before initiating Interactive Remote Access
- Maintaining up-to-date patch levels for operating systems and applications used to initiate Interactive Remote Access
- Disabling VPN "split-tunneling" or "dual-homed" workstations before initiating Interactive Remote Access
- For vendors, contractors, or consultants: include language in contracts that requires adherence to the Responsible Entity's Interactive Remote Access controls

1.1.3 Physical security of BES Cyber Systems (CIP-006)

- Strategy for protecting Cyber Assets from unauthorized physical access
- Acceptable physical access control methods
- Monitoring and logging of physical ingress

1.1.4 System security management (CIP-007)

- Strategies for system hardening
- Acceptable methods of authentication and access control
- Password policies including length, complexity, enforcement, prevention of brute force attempts

- Monitoring and logging of BES Cyber Systems

1.1.5 Incident reporting and response planning (CIP-008)

- Recognition of Cyber Security Incidents
- Appropriate notifications upon discovery of an incident
- Obligations to report Cyber Security Incidents

1.1.6 Recovery plans for BES Cyber Systems (CIP-009)

- Availability of spare components
- Availability of system backups

1.1.7 Configuration change management and vulnerability assessments (CIP-010)

- Initiation of change requests
- Approval of changes
- Break-fix processes

1.1.8 Information protection (CIP-011)

- Information access control methods
- Notification of unauthorized information disclosure
- Information access on a need-to-know basis

1.1.9 Declaring and responding to CIP Exceptional Circumstances

- Processes to invoke special procedures in the event of a CIP Exceptional Circumstance
- Processes to allow for exceptions to policy that do not violate CIP requirements

Requirements relating to exceptions to a Responsible Entity's security policies were removed because it is a general management issue that is not within the scope of a reliability requirement. It is an internal policy requirement and not a reliability requirement. However, Responsible Entities are encouraged to continue this practice as a component of their cyber security policies.

In this and all subsequent required approvals in the NERC CIP Reliability Standards, the Responsible Entity may elect to use hardcopy or electronic approvals to the extent that there is sufficient evidence to ensure the authenticity of the approving party.

Requirement R2:

~~Using the list of assets containing low impact BES Cyber Systems from CIP-002, the intent of the requirement~~The intent of Requirement R2 is for each Responsible Entity to create, document, and implement one or more cyber security plan(s) that ~~addresses~~address the security objective ~~criteria~~ for the protection of low impact BES Cyber Systems. ~~The protections required by Requirement R2 reflect the level of risk that misuse or the unavailability of low impact BES Cyber Systems poses to the BES. The intent is that the~~The required protections are designed to

be part of a program that covers the low impact BES Cyber Systems collectively ~~either~~ at an asset ~~or site~~ level (based on the list of assets containing low impact BES Cyber Systems identified in CIP-002), but not at an individual device or system level.

~~There are four subject matter areas, as identified in Attachment 1, that must be covered by the cyber security plan: (1) cyber security awareness, (2) physical security controls, (3) electronic access controls for LERC and~~

~~**Dial-up Connectivity**, and (4) Cyber Security Incident response.~~

Requirement R2, Attachment 1

As noted, Attachment 1 contains the sections that must be included in the cyber security plan(s). The intent is to allow entities that have a combination of high, medium, and low impact BES Cyber Systems the flexibility to choose, if desired, to cover their low impact BES Cyber Systems (or any subset) under their programs used for the high or medium impact BES Cyber Systems rather than maintain two separate programs. The purpose of the cyber security plan(s) in Requirement R2 is for Responsible Entities to use the cyber security plan(s) as a means of documenting their approaches to meeting the subject matter areas. The cyber security plan(s) can be used to reference other policies and procedures that demonstrate "how" the Responsible Entity is meeting each of the subject matter areas, or Responsible Entities can develop comprehensive cyber security plan(s) that contain all of the detailed implementation content solely within the cyber security plan itself. To meet the obligation for the cyber security plan, the expectation is that the cyber security plan contains or references sufficient details to address the implementation of each of the required subject matters areas.

Guidance for each of the ~~four~~ subject matter areas of Attachment 1 is provided below.

Requirement R2, Attachment 1, Section 1 – Cyber Security Awareness

The intent of the cyber security awareness program is for entities to reinforce good cyber security practices with their personnel at least once every 15 calendar months. The entity has the discretion to determine the topics to be addressed and the manner in which it will communicate these topics. As evidence of compliance, the Responsible Entity should be able to produce the awareness material that was delivered according to the delivery method(s) (e.g., posters, emails, or topics at staff meetings, etc.). The Responsible Entity is not required to maintain lists of recipients and track the reception of the awareness material by personnel.

Although the focus of the awareness is cyber security, it does not mean that only technology-related topics can be included in the program. Appropriate physical security topics (e.g., tailgating awareness and protection of badges for physical security, or "If you see something, say something" campaigns, etc.) are valid for cyber security awareness. The intent is to cover topics concerning any aspect of the protection of BES Cyber Systems.

Requirement R2, Attachment 1, Section 2 – Physical Security Controls

The Responsible Entity must document and implement methods to control physical access to (1) the asset or the locations of low impact BES Cyber Systems ~~at assets containing low impact BES Cyber System(s)~~ within the asset, and (2) ~~LEAPs~~Cyber Assets that implement the electronic access control(s) specified by the Responsible Entity in Section 3.1, if any. If ~~the LEAP is~~these Cyber Assets implementing the electronic access controls are located within the ~~BES asset~~ same asset as the low impact BES Cyber Asset(s) and ~~inherits~~inherit the same physical access controls outlined in Section 2, this can be noted by the Responsible Entity in either its policies or cyber security plan(s) to avoid duplicate documentation of the same controls.

The Responsible Entity has the flexibility ~~in the selection of~~to select the methods used to meet the objective ~~to control~~ of controlling physical access to (1) the asset(s) containing low impact BES Cyber ~~Systems,~~System(s) or the low impact BES Cyber Systems themselves~~, or LEAPs~~ and (2) the electronic access control Cyber Assets specified by the Responsible Entity, if any. The

Responsible Entity may use one or a combination of physical access controls, monitoring controls, or other operational, procedural, or technical physical security controls. Entities may use perimeter controls (e.g., fences with locked gates, guards, or site access policies, etc.) or more granular areas of physical access control in areas where low impact BES Cyber Systems are located, such as control rooms or control houses. User authorization programs and lists of authorized users for physical access are not required although they are an option to meet the security objective.

The security objective is to control the physical access based on need as determined by the Responsible Entity. The need for physical access can be documented at the policy level for access to the site or systems, including LEAPs.. The requirement does not obligate an entity to specify a need for each physical access or authorization of a useran individual for physical access.

Monitoring as a physical security control can be used as a complement or an alternative to physical access control. Examples of monitoring controls include, but are not limited to: (1) alarm systems to detect motion or entry into a controlled area, or (2) human observation of a controlled area. Monitoring does not necessarily require logging and maintaining logs but could include monitoring that physical access has occurred or been attempted (e.g., door alarm, or human observation, etc.). The monitoring does not need to be per low impact BES Cyber System but should be at the appropriate level to meet the security objective of controlling physical access.

User authorization programs and lists of authorized users for physical access are not required although they are an option to meet the security objective.

Requirement R2, Attachment 1, Section 3 – Electronic Access Controls

Section 3 requires the establishment of boundary protectionselectronic access controls for assets containing low impact BES Cyber Systems when the low impact BES Cyber Systems have bi-directionalthere is routable protocol communication or Dial-up Connectivity to devices external to between Cyber Asset(s) outside of the asset containing the low impact BES Cyber Systems. The establishment of boundary protections is intended to control communication either into the asset containing low impact BES Cyber System(s) or toand the low impact BES Cyber System itself to (s) within such asset. The establishment of electronic access controls is intended to reduce the risks associated with uncontrolled communication using routable protocols or Dial-up Connectivity. The term "electronic access control" is used in the general sense, i.e., to control access, and not in the specific technical sense requiring authentication, authorization, and auditing. The Responsible Entity is not required to establish LERC communication or a LEAP if there is no bi-directional routable protocol communication or Dial-up Connectivity present. In the case where there is no external bi-directional routable protocol communication or Dial-up Connectivity, the Responsible Entity can document the absence of such communication in its low impact cyber security plan(s).

The defined terms LERCWhen implementing Section 3.1, Responsible Entities should note that electronic access controls to permit only necessary inbound and LEAPoutbound electronic access are used to avoid confusion with the similar terms usedrequired for highcommunications when those communications meet all three of the criteria identified in Section 3.1. The

Responsible Entity should evaluate the communications and mediumwhen all three criteria are met, the Responsible Entity must document and implement electronic access control(s).

When identifying electronic access controls, Responsible Entities are provided flexibility in the selection of the electronic access controls that meet their operational needs while meeting the security objective of allowing only necessary inbound and outbound electronic access to low impact BES Cyber Systems (e.g., External Routablethat use routable protocols between a low impact BES Cyber System(s) and Cyber Asset(s) outside the asset.

In essence, Responsible Entities are to determine whether there is communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s) that uses a routable protocol when entering or leaving the asset or Dial-up Connectivity (ERC) or to the low impact BES Cyber System(s). Where such communication is present, Responsible Entities should document and implement electronic access control(s). Where routable protocol communication for time-sensitive protection or control functions between intelligent electronic devices that meets the exclusion language is present, Responsible Entities should document that communication, but are not required to establish any specific electronic access controls.

The inputs to this requirement are the assets identified in CIP-002 as containing low impact BES Cyber System(s); therefore, the determination of routable protocol communications or Dial-up Connectivity is an attribute of the asset. However, any communication that provides no access to or from the low impact BES Cyber System(s), but happens to be located at the asset with the low impact BES Cyber System(s), does not require evaluation for electronic access controls.

Electronic Access Point (EAP)). To future-proof the standards, and inControl Exclusion

In order to avoid future technology issues, the definitions specificallyobligations for electronic access controls exclude "point-to-point communications between intelligent electronic devices that use routable communication protocols for time-sensitive protection or control functions between Transmission station or substation assets containing low impact BES Cyber Systems,", such as IEC TR-61850-90-5 R-GOOSE messaging. This does not exclude Control Center communication but rather excludes the communication between the intelligent electronic devices themselves.Time-sensitive in this context generally means functions that would be negatively impacted by the latency introduced in the communications by the required electronic access controls. This time-sensitivity exclusion does not apply to SCADA communications which typically operate on scan rates of 2 seconds or greater. While technically time-sensitive, SCADA communications over routable protocols can withstand the delay introduced by electronic access controls. Examples of excluded time-sensitive communications are those communications which may necessitate the tripping of a breaker within a few cycles. A Responsible Entity using this technology is not expected to implement a LEAP.the electronic access controls noted herein. This exception was included so as not to inhibit the functionality of the time-sensitive requirementscharacteristics related to this technology norand not to preclude the use of such time-sensitive reliability enhancing functions if they use a routable protocol in the future.

When determining whether **Considerations for Determining Routable Protocol Communications**

In order for Responsible Entities to determine whether electronic access controls need to be implemented, the Responsible Entity needs to determine whether there is LERC to the low impact BES Cyber System, the definition uses the phrases "direct user-initiated interactive access or a direct device-to-device connection to communication between a low impact BES Cyber System(s) fromand a Cyber Asset(s) outside the asset containing thosethe low impact BES Cyber System(s) viathat use a routable protocol when entering or leaving the asset.

When determining whether a bi-directional routable protocol connection." The intent of "direct" in the definition is to indicate LERC exists if a person is sitting at another device outside ofentering or leaving the asset containing the low impact BES Cyber System, and (s), Responsible Entities have flexibility in identifying an approach to making this evaluation. One approach is for Responsible Entities to identify an "electronic boundary" associated with the asset containing low impact BES Cyber System(s). This is not an Electronic Security Perimeter *per se*, but a demarcation that demonstrates the person can connect to logon, configure, read, or interact, etc. with the low impact BES Cyber System using a bi-directional routable protocol within a single end-to-end protocol session even if there is a serial to routable protocol conversion. The reverse case would also be LERC, in which the individual sits at thecommunication entering or leaving the asset between a low impact BES Cyber System and connectsCyber Asset(s) outside the asset to then have electronic access controls implemented. This electronic boundary may vary by asset type (Control Center, substation, generation resource) and the specific configuration of the asset. If this approach is used, the intent is for the Responsible Entity to define the electronic boundary such that the low impact BES Cyber System(s) located at the asset are contained within the "electronic boundary." This is strictly for determining which routable protocol communications and networks are internal or inside or local to a device the asset and which are external to or outside the asset.

Alternatively, the Responsible Entity may find the concepts of what is inside and outside to be intuitively obvious for a Cyber Asset(s) outside the asset containing low impact BES Cyber Systems using a single end-to-end bi-directional routable protocol session. Additionally, for "device to System(s) communicating to a low impact BES Cyber System(s) inside the asset. This may be the case when a low impact BES Cyber System(s) is communicating with a Cyber Asset many miles away and a clear and unambiguous demarcation exists. In this case, a Responsible Entity may decide not to identify an "electronic boundary," but rather to simply leverage the unambiguous asset demarcation to ensure that the electronic access controls are placed between the low impact BES Cyber System(s) and the Cyber Asset(s) outside the asset.

Determining Electronic Access Controls

Once a Responsible Entity has determined that there is routable communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s) that uses a routable protocol when entering or leaving the asset containing the low impact BES Cyber System(s), the Responsible Entity documents and implements its chosen electronic access control(s). The control(s) must allow only "necessary" inbound and outbound electronic access as determined by the Responsible Entity. The Responsible Entity must be able to explain the reasons for the electronic access permitted. The reasoning for the

"necessary" inbound and outbound electronic access controls can be documented within the Responsible Entity's cyber security plan(s) or other policies or procedures associated with the electronic access controls.

Concept Diagrams

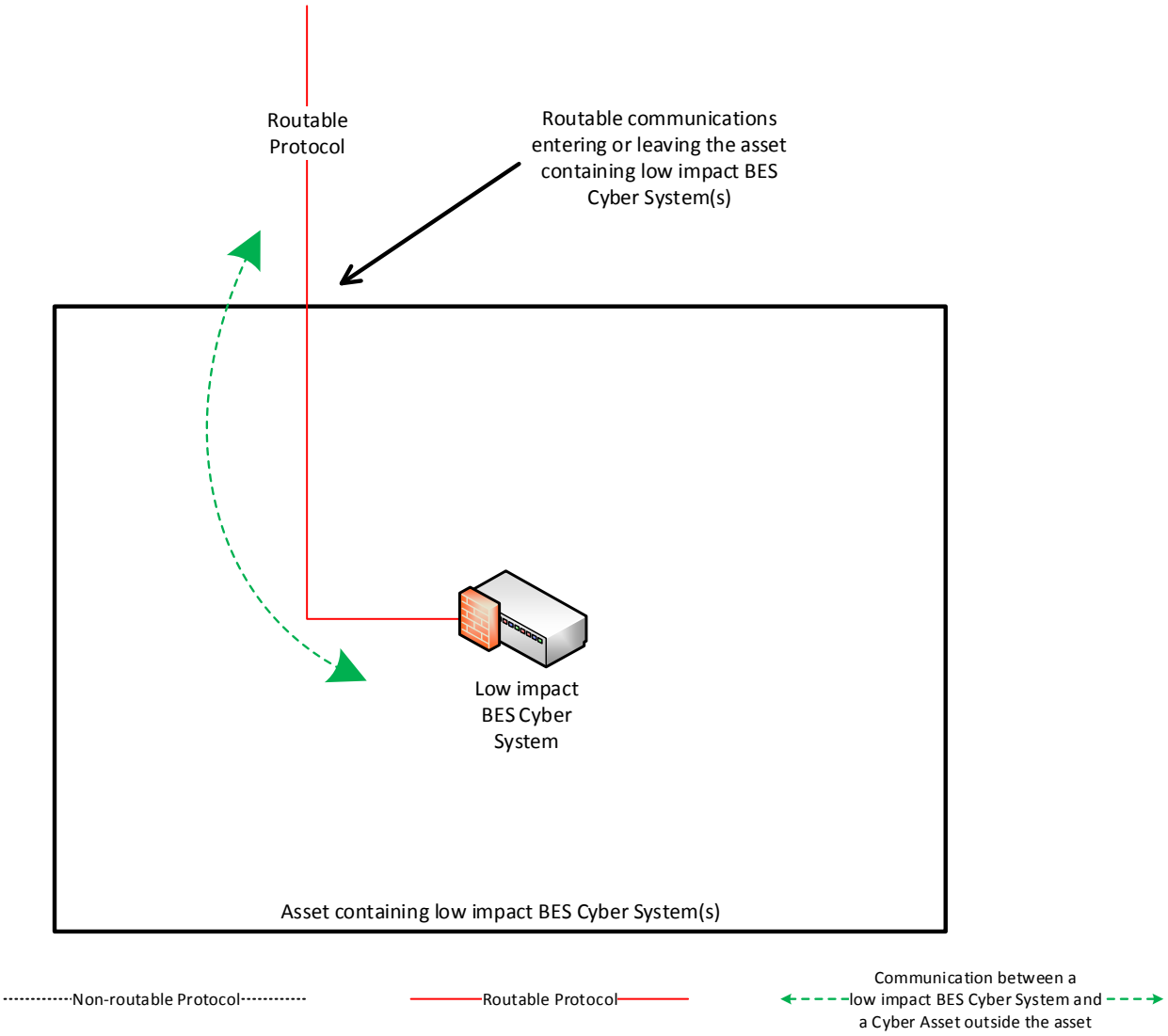
The diagrams on the following pages are provided as examples to illustrate various electronic access controls at a conceptual level. Regardless of the concepts or configurations chosen by the Responsible Entity, the security objective of permitting only necessary inbound and outbound electronic access for communication between low impact BES Cyber Systems and Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s) using a routable protocol when entering or leaving the asset must be met.

NOTE:

- This is not an exhaustive list of applicable concepts.
- The same legend is used in each diagram; however, the diagram may not contain all of the articles represented in the legend.

Reference Model 1 – Host-based Inbound & Outbound Access Permissions

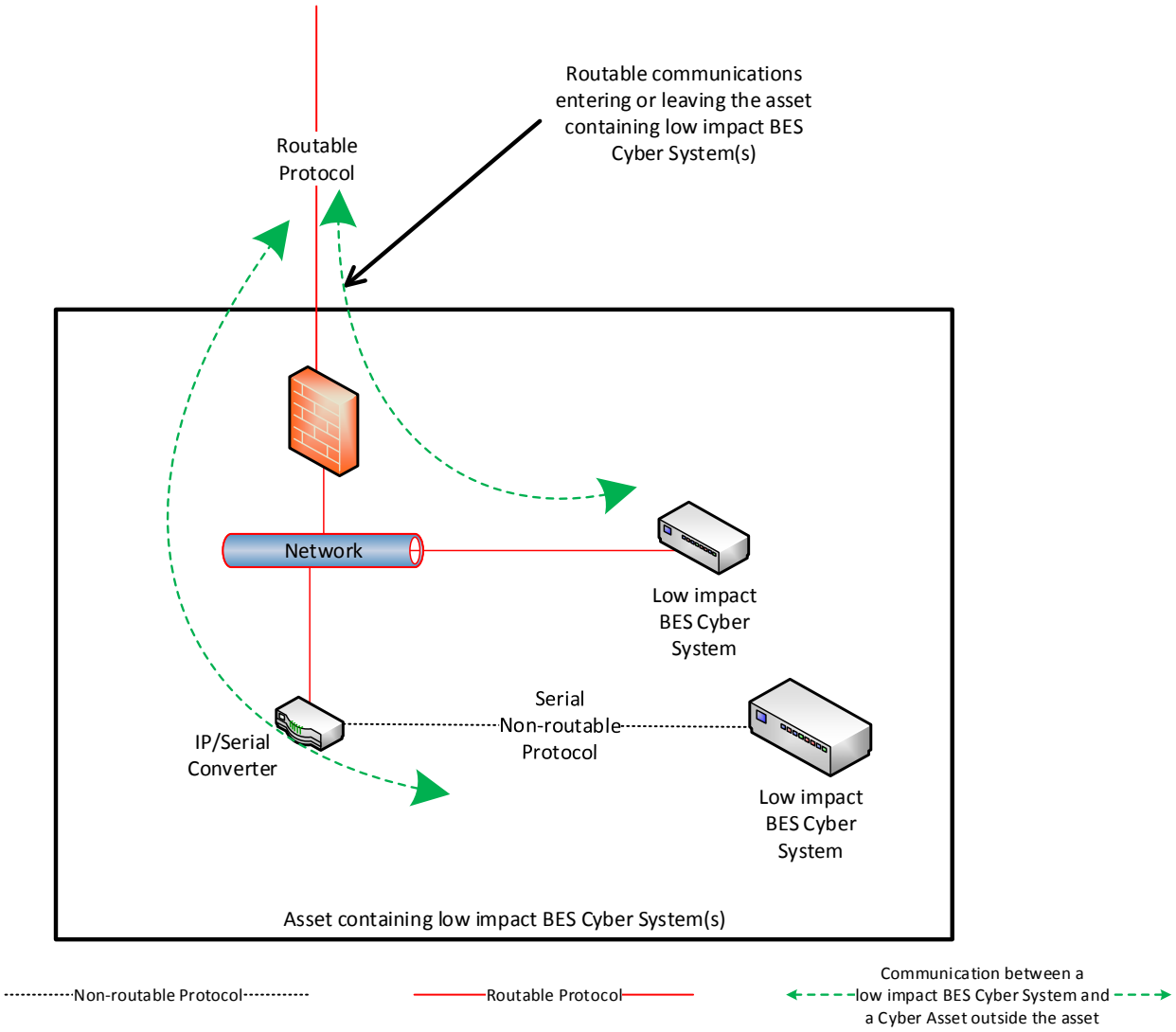
The Responsible Entity may choose to utilize a host-based firewall technology on the low impact BES Cyber System(s) itself that manages the inbound and outbound electronic access permissions so that only necessary inbound and outbound routable protocol access is allowed between the low impact BES Cyber System(s) and the Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s). When permitting the inbound and outbound electronic access permissions, at a minimum, the permissions need to restrict source and destination addresses, or a range of addresses when necessary. Responsible Entities may further restrict electronic access using ports and services based on the capability of the electronic access control, low impact BES Cyber System, application, etc.



Reference Model 1

Reference Model 2 – Network-based Inbound & Outbound Access Permissions

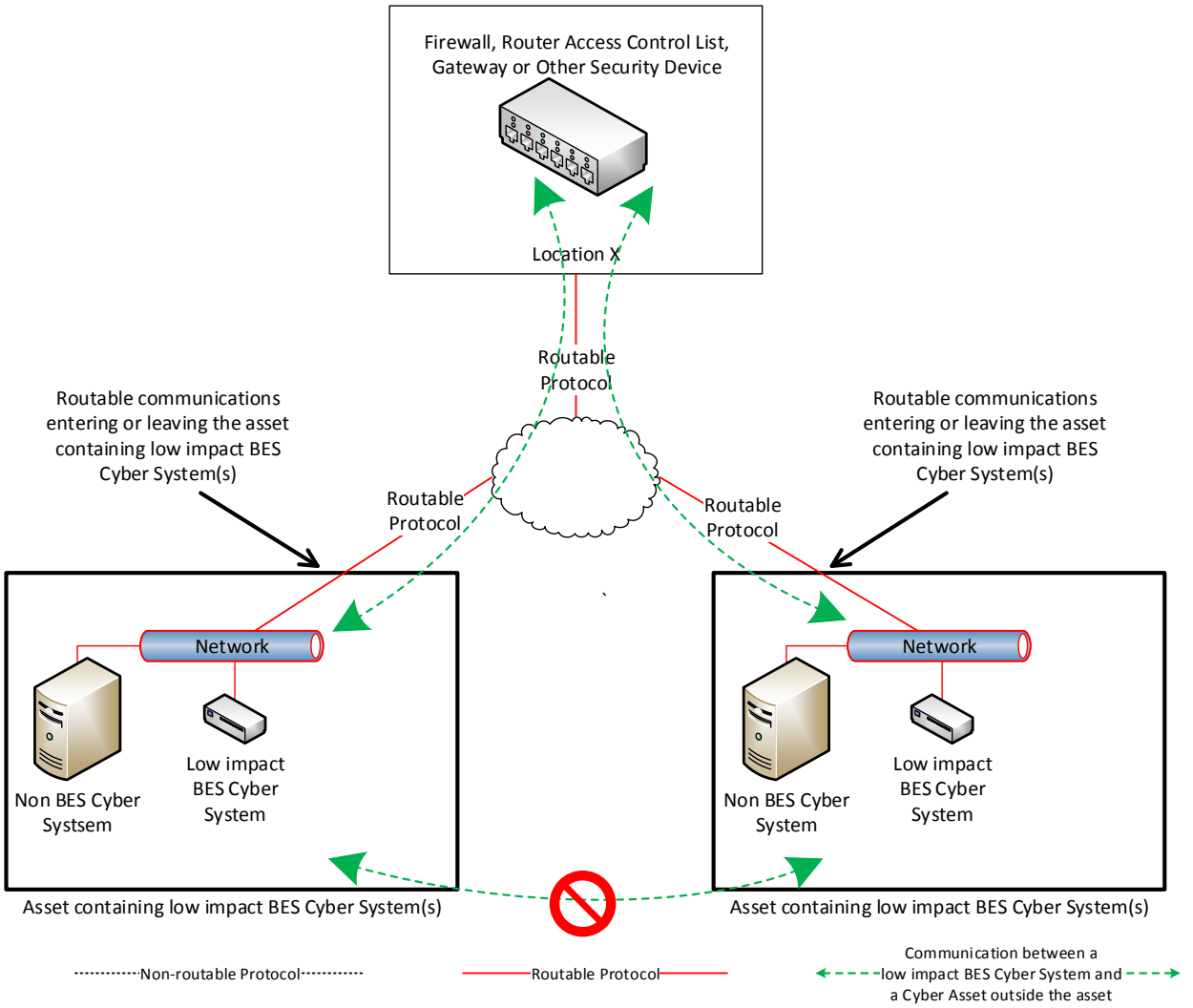
The Responsible Entity may choose to use a security device that permits only necessary inbound and outbound electronic access to the low impact BES Cyber System(s) within the asset containing the low impact BES Cyber System(s). In this example, two low impact BES Cyber Systems are accessed using the routable protocol that is entering or leaving the asset containing the low impact BES Cyber System(s). The IP/Serial converter is continuing the same communications session from the Cyber Asset(s) that are outside the asset to the low impact BES Cyber System(s). The security device provides the electronic access controls to permit only necessary inbound and outbound routable protocol access to the low impact BES Cyber System(s). When permitting the inbound and outbound electronic access permissions, at a minimum, the permissions need to restrict source and destination addresses, or a range of addresses when necessary. Responsible Entities may further restrict electronic access using ports and services based on the capability of the electronic access control, low impact BES Cyber System, application, etc.



Reference Model 2

Reference Model 3 – Centralized Network-based Inbound & Outbound Access Permissions

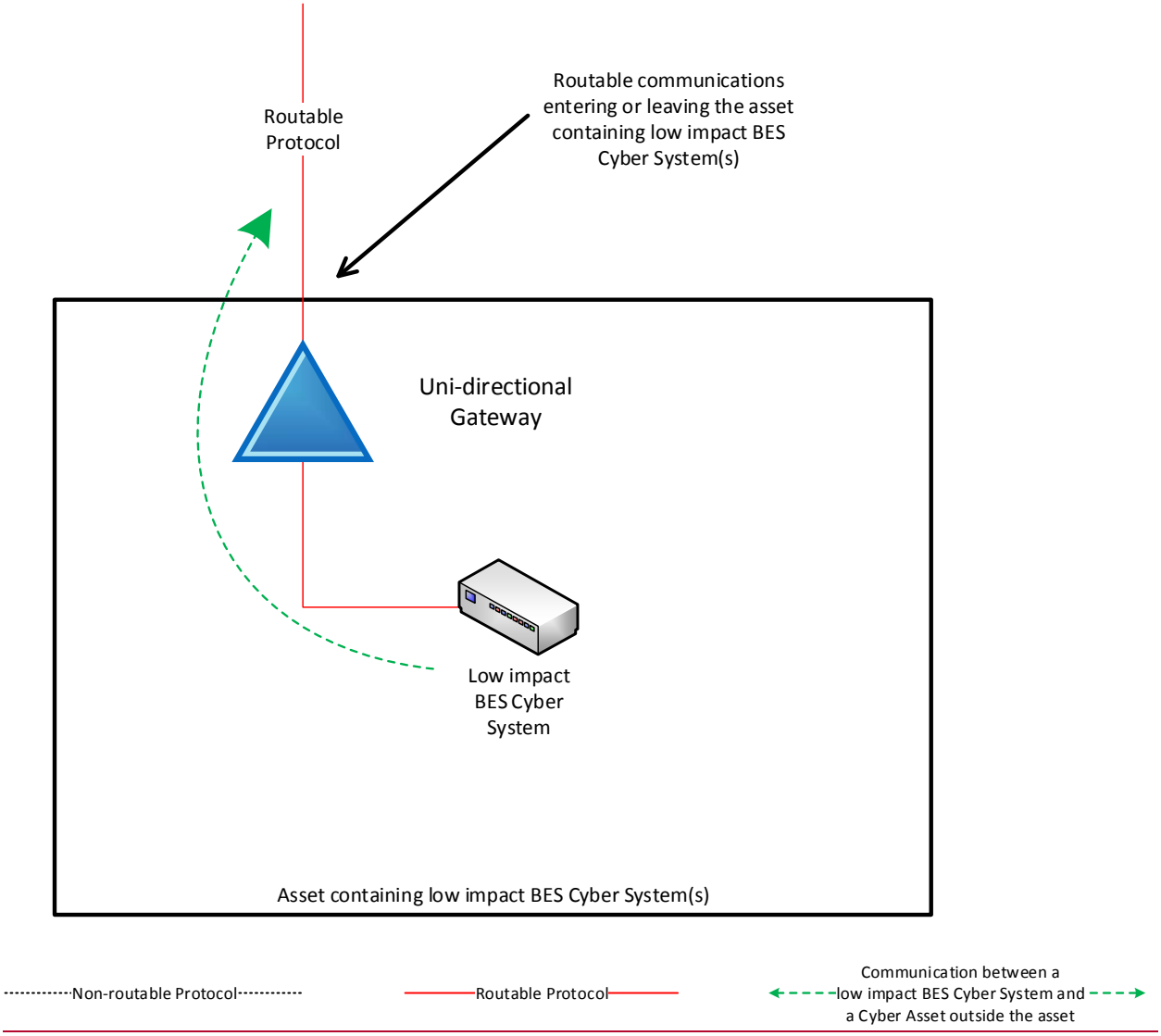
The Responsible Entity may choose to utilize a security device at a centralized location that may or may not be another asset containing low impact BES Cyber System(s). The electronic access control(s) do not necessarily have to reside inside the asset containing the low impact BES Cyber System(s). A security device is in place at "Location X" to act as the electronic access control and permit only necessary inbound and outbound routable protocol access between the low impact BES Cyber System(s) and the Cyber Asset(s) outside each asset containing low impact BES Cyber System(s). Care should be taken that electronic access to or between each asset is through the electronic access controls at the centralized location. When permitting the inbound and outbound electronic access permissions, at a minimum, the permissions need to restrict source and destination addresses, or a range of addresses when necessary. Responsible Entities can further restrict electronic access using ports and services based on the capability of the electronic access control, low impact BES Cyber System, application, etc.



Reference Model 3

Reference Model 4 – Uni-directional Gateway

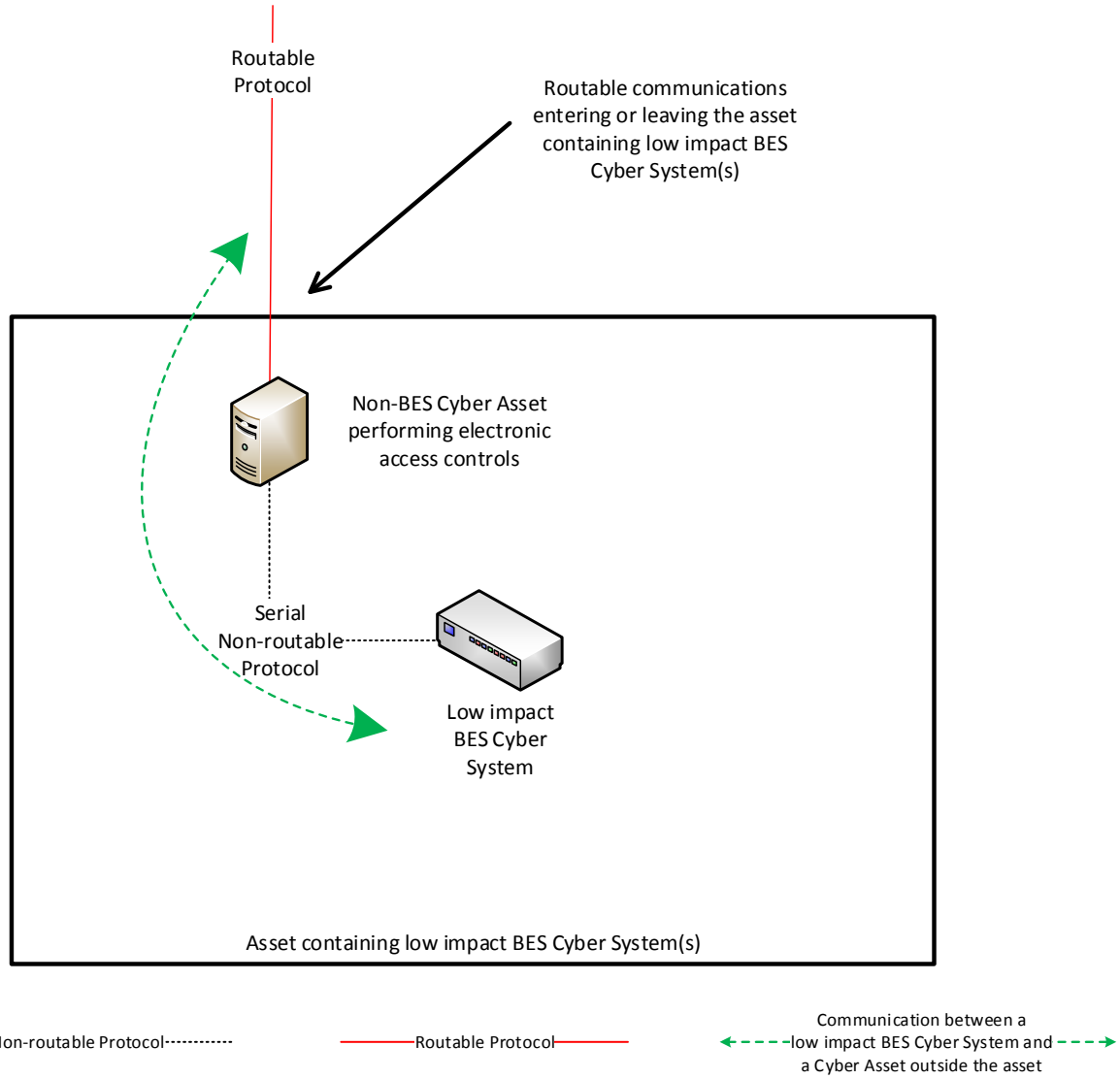
The Responsible Entity may choose to utilize a uni-directional gateway as the electronic access control. The low impact BES Cyber System(s) is not accessible (data cannot flow into the low impact BES Cyber System) using the routable protocol entering the asset due to the implementation of a "one-way" (uni-directional) path for data to flow. The uni-directional gateway is configured to permit only the necessary outbound communications using the routable protocol communication leaving the asset.



Reference Model 4

Reference Model 5 – User Authentication

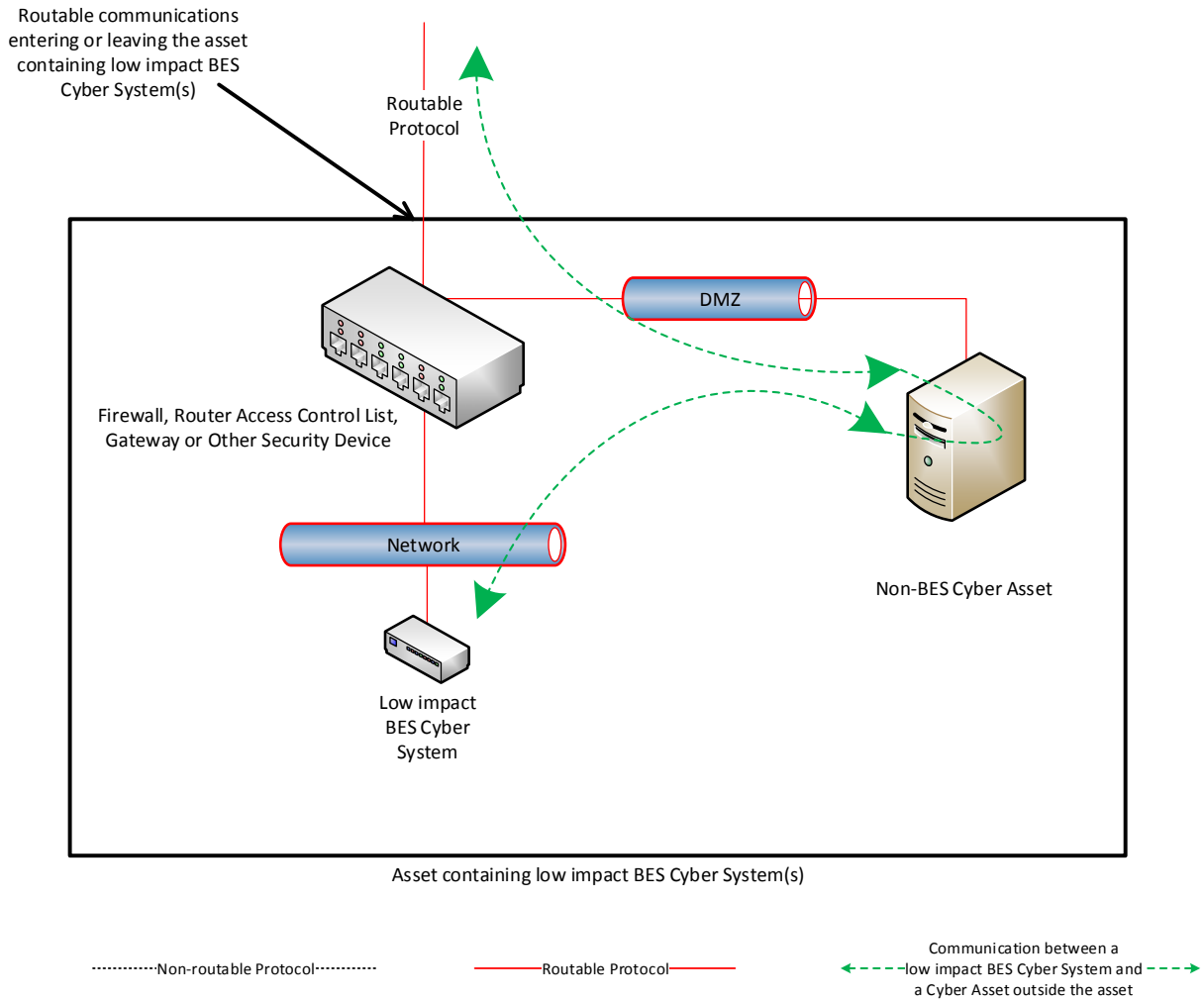
This reference model demonstrates that Responsible Entities have flexibility in choosing their electronic access controls so long as the security objective of the requirement is met. The Responsible Entity may choose to utilize a non-BES Cyber Asset located at the asset containing the low impact BES Cyber System that requires authentication for communication from the Cyber Asset(s) outside the asset. This non-BES Cyber System performing the authentication permits only authenticated communication to connect to the low impact BES Cyber System(s), meeting the first half of the security objective to permit only necessary inbound electronic access. Additionally, the non-BES Cyber System performing authentication must be configured such that it permits only necessary outbound communication meeting the second half of the security objective. Often, the outbound communications may be controlled in this network architecture by permitting no communication be initiated from the low impact BES Cyber System. This configuration may be beneficial when the only communication to a device is for user-initiated interactive access.



Reference Model 5

Reference Model 6 – Indirect Access

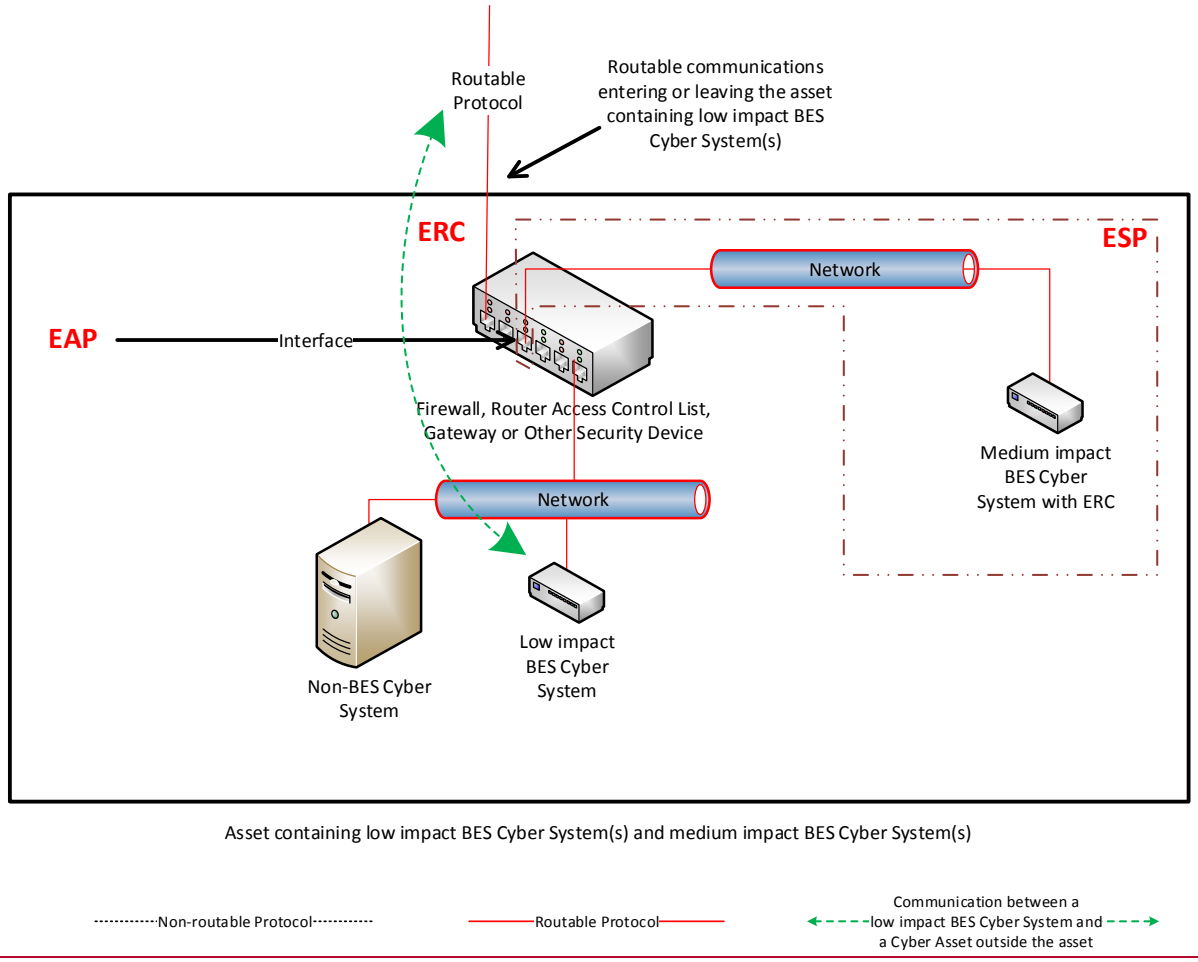
In implementing its electronic access controls, the Responsible Entity may identify that it has indirect access between the low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System through a non-BES Cyber Asset located within the asset. This indirect access meets the criteria of having communication between the low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System. In this reference model, the Responsible Entity needs to implement electronic access controls that permit only necessary inbound and outbound electronic access to the BES Cyber System. Consistent with the other reference models provided, this electronic access is controlled using the security device ~~connection," LERC exists if the Responsible Entity has devices outside of the asset containing the low impact BES Cyber System sending or receiving bi-directional routable communication to or from the low impact BES Cyber System.~~ that is restricting the communication that is entering or leaving the asset.



Reference Model 6

Reference Model 7 – Electronic Access Controls at assets containing low impact BES Cyber Systems and ERC

There is both a routable protocol entering and leaving the asset containing the low impact BES Cyber System(s) that is used by Cyber Asset(s) outside the asset and ERC present in this reference model because there is at least one medium impact BES Cyber System and one low impact BES Cyber System within the asset using the routable protocol communications. The Responsible Entity may choose to leverage an interface on the medium impact Electronic Access Control or Monitoring Systems (EACMS) to provide electronic access controls. The EACMS is therefore performing multiple functions – as a medium impact EACMS and as implementing electronic access controls for an asset containing low impact BES Cyber Systems.



Reference Model 7

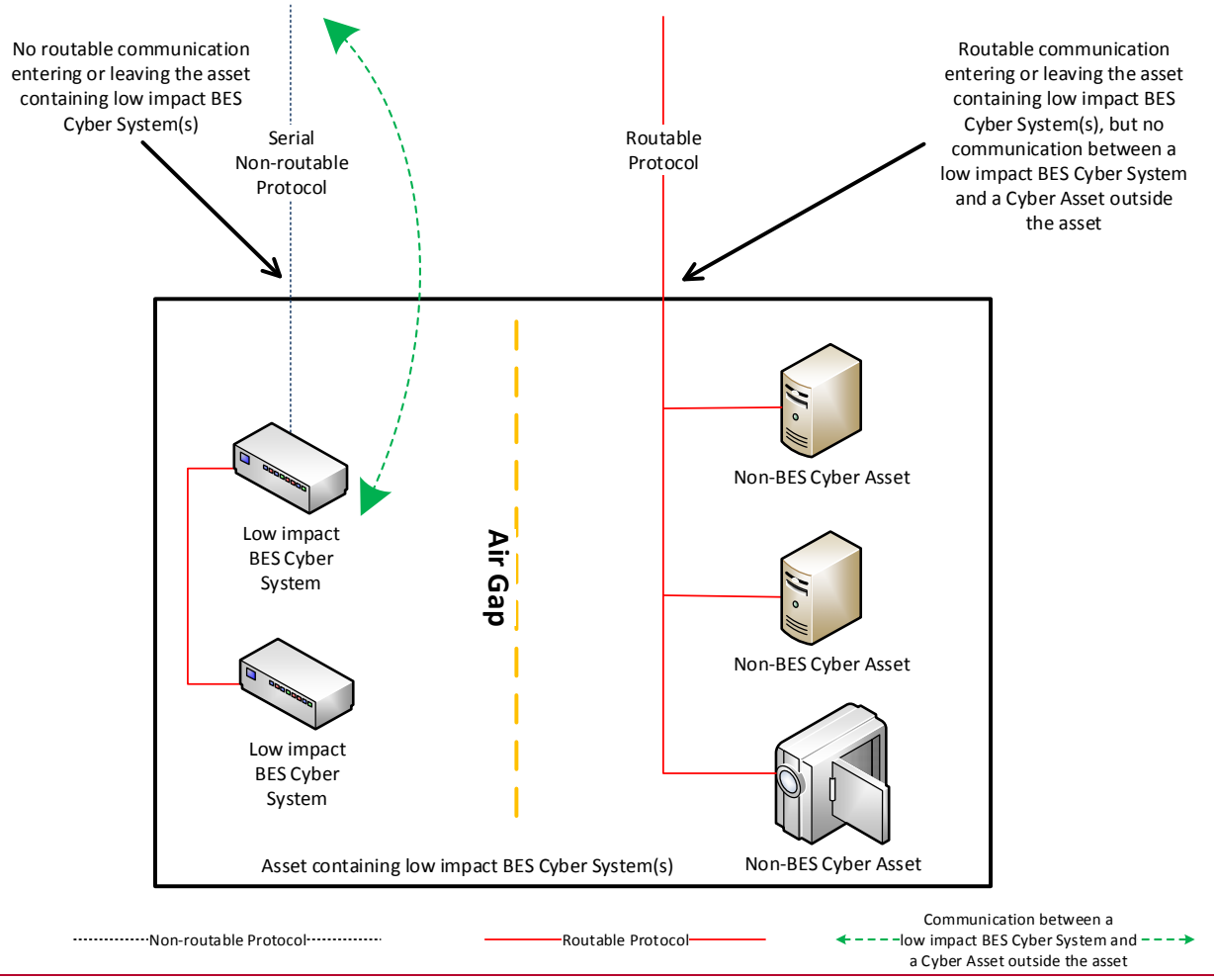
Reference Model 8 – Physical Isolation and Serial Non-routable Communications – No Electronic Access Controls Required

In this reference model, the criteria for requiring the implementation of electronic access controls are not met. This reference model demonstrates three concepts:

1) physical isolation of the low impact BES Cyber System(s) from the routable protocol communication entering or leaving the asset containing the low impact BES Cyber System(s), commonly referred to as an 'air gap', mitigates the need to implement the required electronic access controls;

2) communication to the low impact BES Cyber System from a Cyber Asset outside the asset containing the low impact BES Cyber System(s) using only a serial non-routable protocol where such communication is entering or leaving the asset mitigates the need to implement the required electronic access controls; and

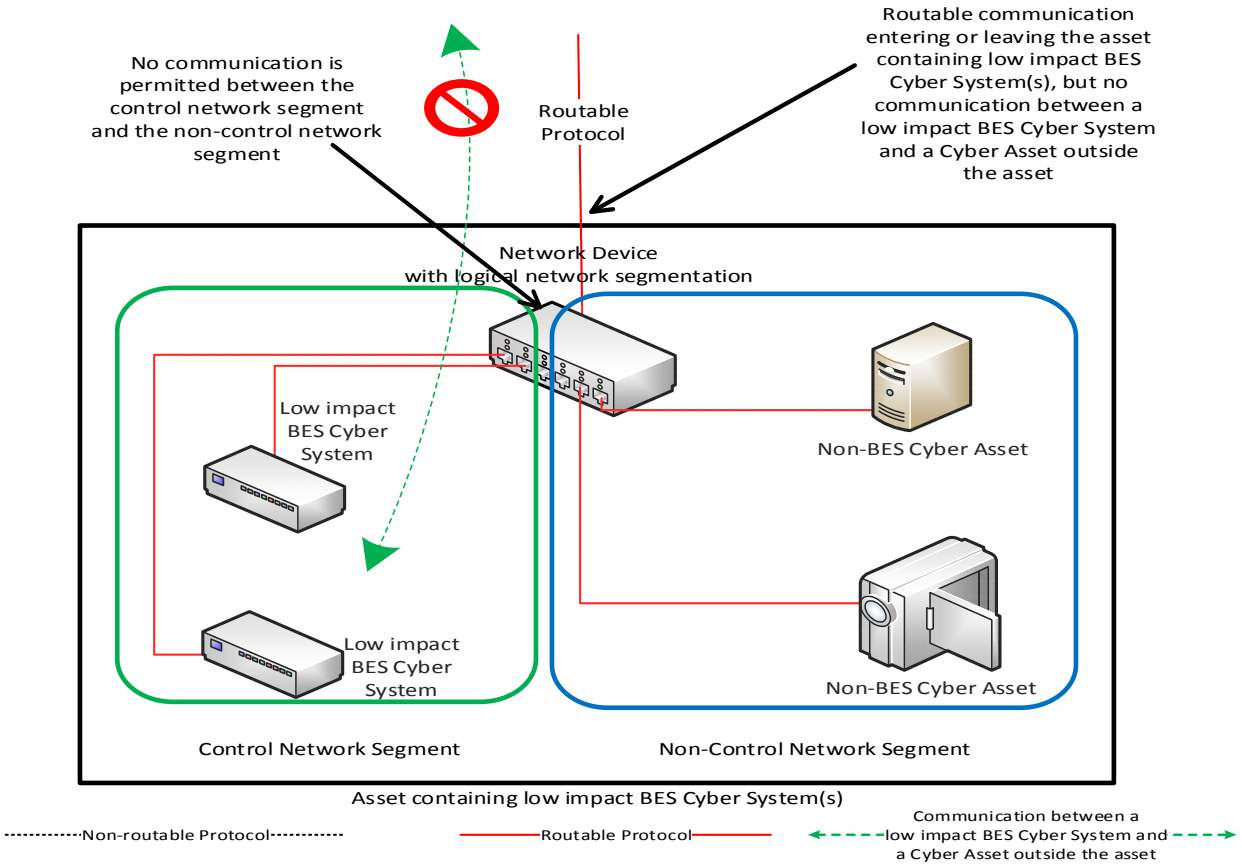
3) routable protocol communication between the low impact BES Cyber System(s) and other Cyber Asset(s), such as the second low impact BES Cyber System depicted, may exist without needing to implement the required electronic access controls so long as the routable protocol communications never leaves the asset containing the low impact BES Cyber System(s).



Reference Model 8

Reference Model 9 – Logical Isolation - No Electronic Access Controls Required

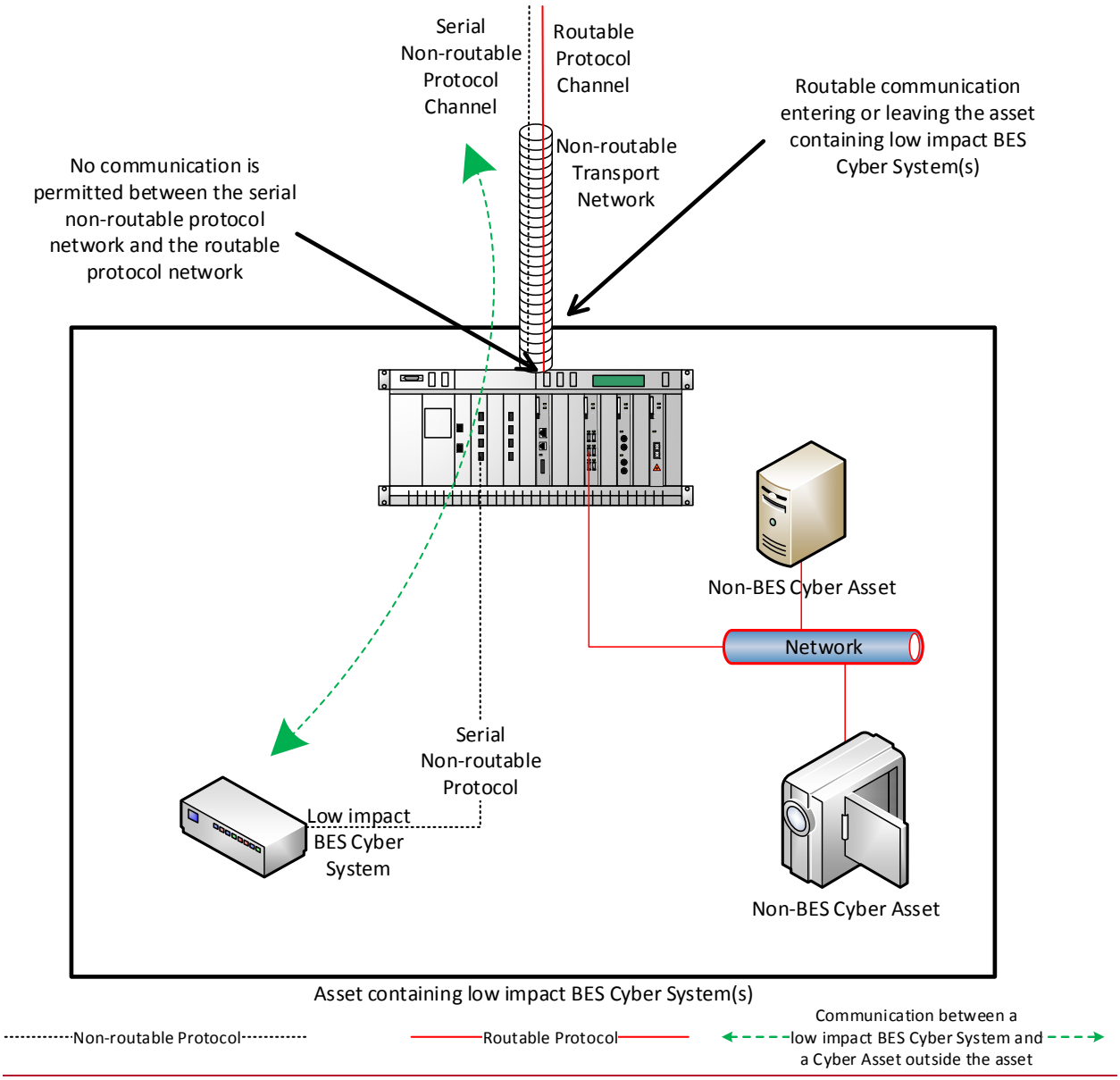
In this reference model, the criteria for requiring the implementation of electronic access controls are not met. The Responsible Entity has logically isolated the low impact BES Cyber System(s) from the routable protocol communication entering or leaving the asset containing low impact BES Cyber System(s). The logical network segmentation in this reference model permits no communication between a low impact BES Cyber System and a Cyber Asset outside the asset. Additionally, no indirect access exists because those non-BES Cyber Assets that are able to communicate outside the asset are strictly prohibited from communicating to the low impact BES Cyber System(s). The low impact BES Cyber System(s) is on an isolated network segment with logical controls preventing routable protocol communication into or out of the network containing the low impact BES Cyber System(s) and these communications never leave the asset using a routable protocol.



Reference Model 9

Reference Model 10 - Serial Non-routable Communications Traversing an Isolated Channel on a Non-routable Transport Network – No Electronic Access Controls Required

This reference model depicts communication between a low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System over a serial non-routable protocol which is transported across a wide-area network using a non-routable technology, such as a Time-Division Multiplexing (TDM) or Synchronous Optical (SONET) network. In this reference model, the criteria requiring electronic access controls are not met. While there is routable protocol communication entering or leaving the asset containing low impact BES Cyber Systems(s) and there is communication between a low impact BES Cyber System and a Cyber Asset outside the asset, the communication between the low impact BES Cyber System and the Cyber Asset outside the asset is not using the routable protocol communication. This model is related to Reference Model 9 in that it relies on logical isolation to prohibit the communication between a low impact BES Cyber System and a Cyber Asset outside the asset from using a routable protocol. In similar configurations, the Responsible Entity should closely evaluate the transport entering or leaving the asset containing low impact BES Cyber System(s). If the communication entering or leaving the asset containing low impact BES Cyber System(s) was routable (such as serial encapsulated in TCP/IP or UDP/IP as depicted Reference Model 2 or Reference Model 5), then the criteria requiring electronic access controls would be met.



Reference Model 10

Dial-up Connectivity When identifying a LEAP, Responsible Entities are provided flexibility in the selection of the interface on a Cyber Asset that controls the LERC. Examples include, but are not limited to, the internal (facing the low impact BES Cyber Systems) interface on an external or host-based firewall, the internal interface on a router that has implemented an access control list (ACL), or other security device. The entity also has flexibility with respect to the location of the LEAP. LEAPs are not required to reside at the asset containing the low impact BES Cyber Systems. Furthermore, the entity is not required to establish a unique physical LEAP per asset containing low impact BES Cyber Systems. Responsible Entities can have a single Cyber Asset containing multiple LEAPs that controls the LERC for more than one asset containing low impact BES Cyber Systems. Locating the Cyber Asset with multiple LEAPs at an external location with multiple assets containing low impact BES Cyber Systems "behind" it, however, should not allow uncontrolled access to assets containing low impact BES Cyber Systems sharing a Cyber Asset containing the LEAP(s).

In Reference Model 4, the communication flows through an IP/Serial converter. LERC is correctly identified in this Reference Model because the IP/Serial converter in this instance is doing nothing more than extending the communication between the low impact BES Cyber System and the Cyber Asset outside the asset containing the low impact BES Cyber System. In contrast, Reference Model 6 has placed a Cyber Asset that performs a complete break or interruption that does not allow the user or device data flow to directly communicate with the low impact BES Cyber System. The Cyber Asset in Reference Model 6 is preventing extending access to the low impact BES Cyber System from the Cyber Asset outside the asset containing the low impact BES Cyber System. The intent is that if the IP/Serial converter that is deployed only does a "pass-through" of the data flow communication, then that "pass-through" data flow communication is LERC and a LEAP is required. However, if that IP/Serial converter performs some type of authentication in the data flow at the asset containing the low impact BES Cyber System before the communication can be sent to the low impact BES Cyber System, then that type of IP/Serial converter implementation is not LERC.

A Cyber Asset that contains interface(s) that only perform the function of a LEAP does not meet the definition of Electronic Access Control or Monitoring System (EACMS) associated with medium or high impact BES Cyber Systems and is not subject to the requirements applicable to an EACMS. However, a Cyber Asset may contain some interfaces that function as a LEAP and other interfaces that function as an EAP for high or medium impact BES Cyber Systems. In this case, the Cyber Asset would also be subject to the requirements applicable to the EACMS associated with the medium or high impact BES Cyber Systems.

Examples of sufficient access controls may include:

- Any LERC for the asset passes through a LEAP with explicit inbound and outbound access permissions defined, or equivalent method by which both inbound and outbound connections are confined to only those that the Responsible Entity deems necessary (e.g., IP addresses, ports, or services).
- As shown in Reference Model 1 below, the low impact BES Cyber System has a host-based firewall that is controlling the inbound and outbound access. In this model, it is also possible that the host-based firewall could be on a non-BES

Cyber Asset. The intent is that the host-based firewall controls the inbound and outbound access between the low impact BES Cyber System and the Cyber Asset in the business network.

- As shown in Reference Model 5 below, a non-BES Cyber Asset has been placed between the low impact BES Cyber System on the substation network and the Cyber Asset in the business network. The expectation is that the non-BES Cyber Asset has provided a "protocol break" so that access to the low impact BES Cyber System is only from the non-BES Cyber Asset that is located within the asset containing the low impact BES Cyber System.

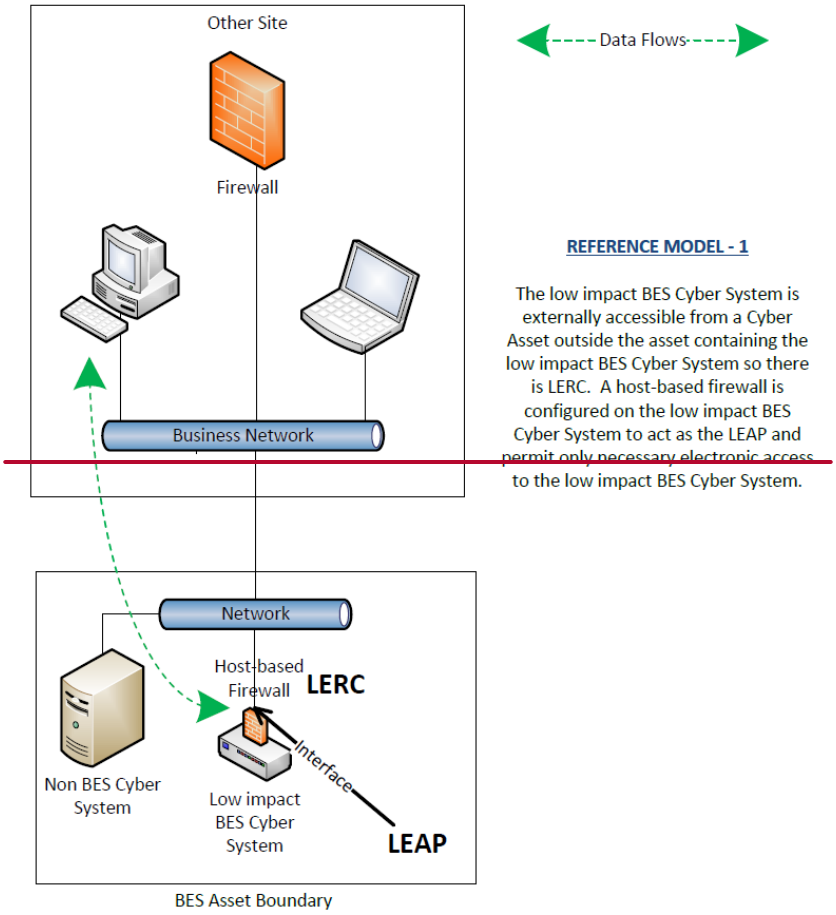
Dial-up Connectivity to a low impact BES Cyber System is set to dial out only (no auto-answer) to a preprogrammed number to deliver data. Incoming Dial-up Connectivity is to a dialback modem, a modem that must be remotely controlled by the control center or control room, has some form of access control, or the low impact BES Cyber System has access control.

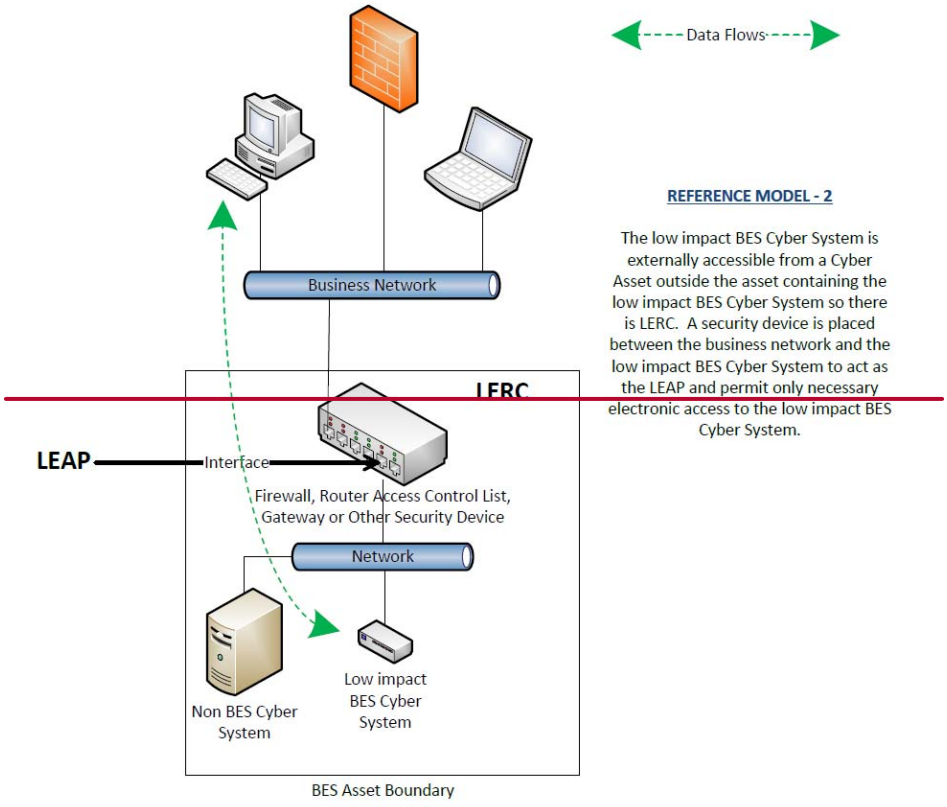
Insufficient Access Controls

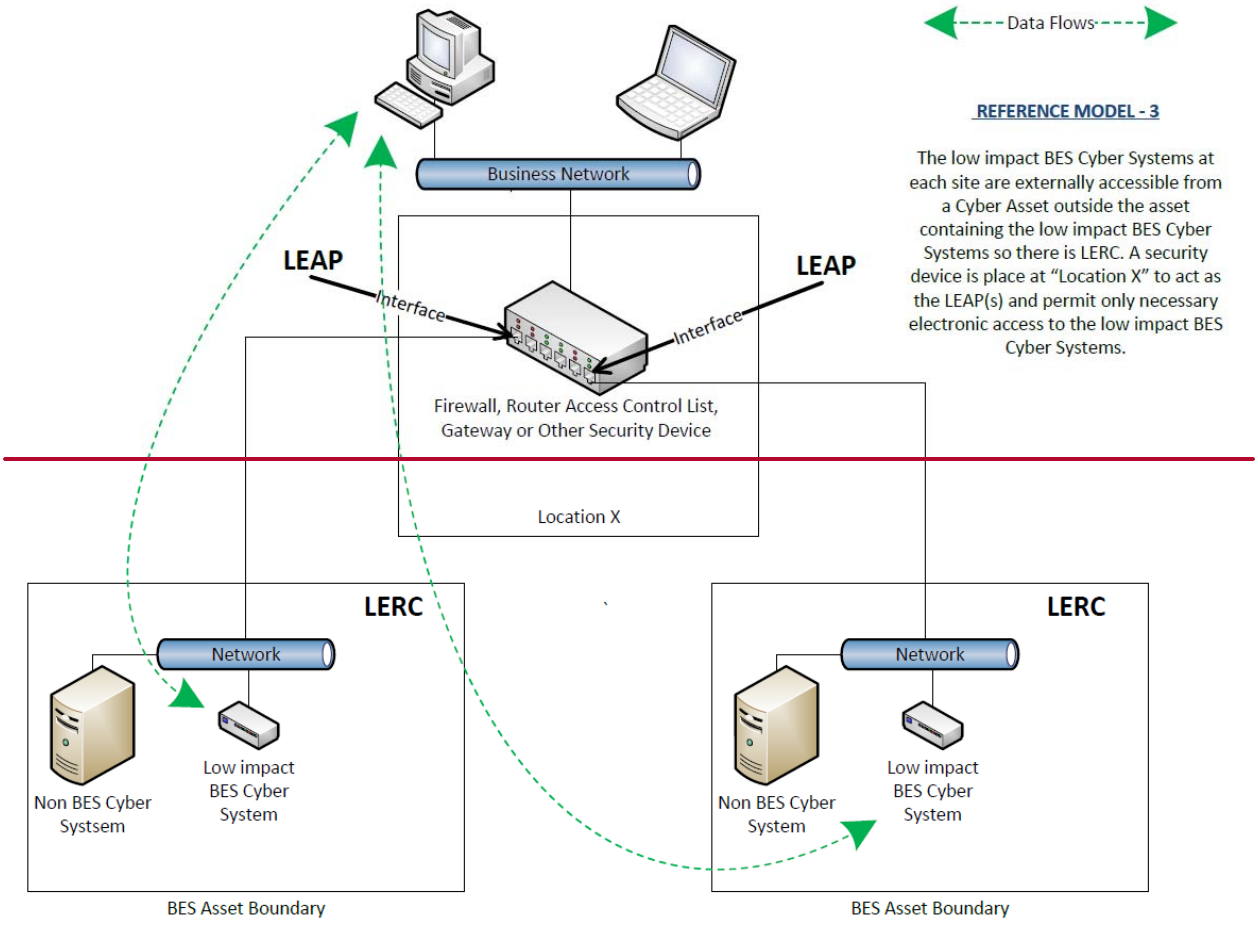
Some examples of situations that would lack sufficient access controls to meet the intent of this requirement include:

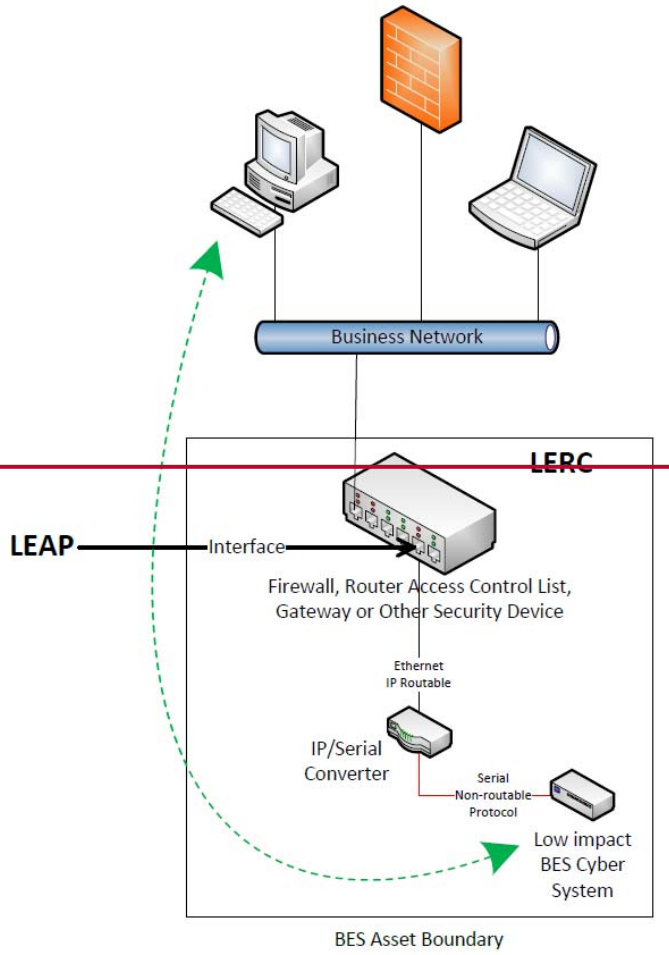
- An asset has Dial-up Connectivity and a low impact BES Cyber System is reachable via an auto-answer modem that connects any caller to the Cyber Asset that has a default password. There is no practical access control in this instance.
- An asset has LERC due to aA low impact BES Cyber System within it havinghas a wireless card on a public carrier that allows the BES Cyber System to be reachable via a public IP address. In essence, low impact BES Cyber Systems should not be accessible from the Internet and search engines such as Shodan.
- In Reference Model 5, using just dualDual-homing or multiple-network interface cards without disabling IP forwarding in the non-BES Cyber Asset within the DMZ to provide separation between the low impact BES Cyber System(s) and the businessexternal network would not meet the intent of "controlling" inbound and outbound electronic access assuming there was no other host-based firewall or other security devicedevices on thatthe non-BES Cyber Asset.

The following diagrams provide reference examples intended to illustrate how to determine whether there is LERC and for implementing a LEAP. While these diagrams identify several possible configurations, Responsible Entities may have additional configurations not identified below.


Other Site
Data Flows
Firewall
Business Network
REFERENCE MODEL - 1
The low impact BES Cyber System is externally accessible from a Cyber Asset outside the asset containing the low impact BES Cyber System so there is LERC. A host-based firewall is configured on the low impact BES Cyber System to act as the LEAP and permit only necessary electronic access to the low impact BES Cyber System.
Network
Host-based Firewall
LERC
Interface
Non BES Cyber System
Low impact BES Cyber System
LEAP
BES Asset Boundary


Data Flows
REFERENCE MODEL - 2
The low impact BES Cyber System is externally accessible from a Cyber Asset outside the asset containing the low impact BES Cyber System so there is LERC. A security device is placed between the business network and the low impact BES Cyber System to act as the LEAP and permit only necessary electronic access to the low impact BES Cyber System.
Business Network
LERC
LEAP
Interface
Firewall, Router Access Control List, Gateway or Other Security Device
Network
Non BES Cyber System
Low impact BES Cyber System
BES Asset Boundary

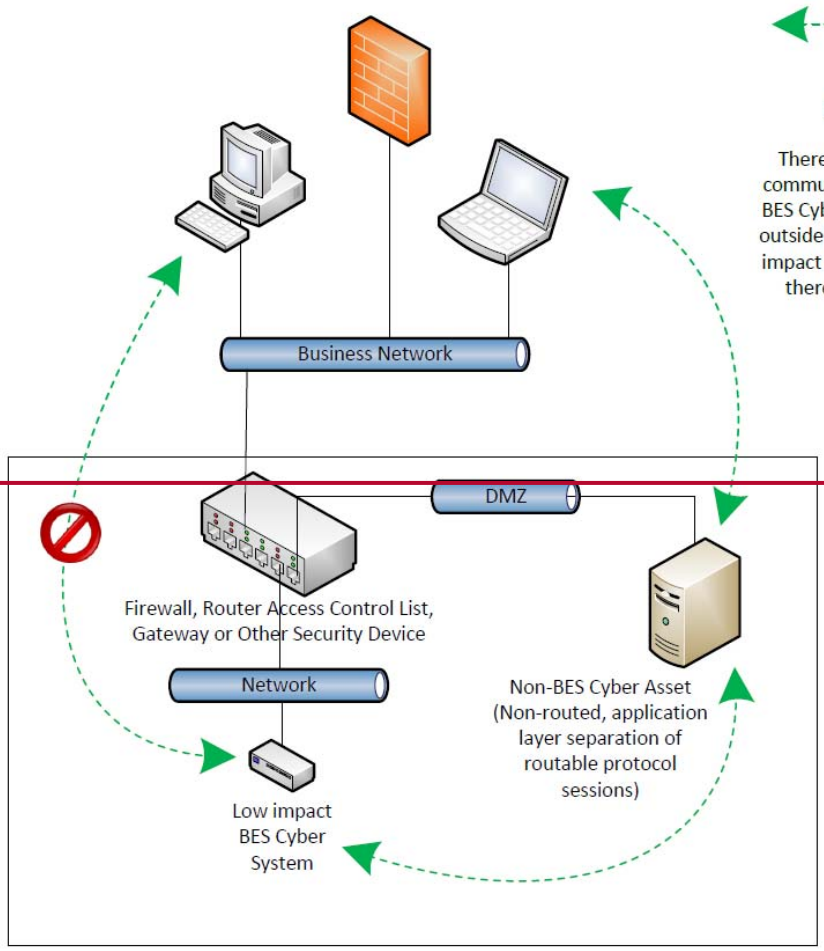

Data Flows
REFERENCE MODEL - 3
The low impact BES Cyber Systems at each site are externally accessible from a Cyber Asset outside the asset containing the low impact BES Cyber Systems so there is LERC. A security device is place at "Location X" to act as the LEAP(s) and permit only necessary electronic access to the low impact BES Cyber Systems.
Business Network
LEAP
Interface
LEAP
Interface
Firewall, Router Access Control List, Gateway or Other Security Device
Location X
LERC
Network
Non BES Cyber Systsem
Low impact BES Cyber System
BES Asset Boundary
LERC
Network
Non BES Cyber System
Low impact BES Cyber System
BES Asset Boundary

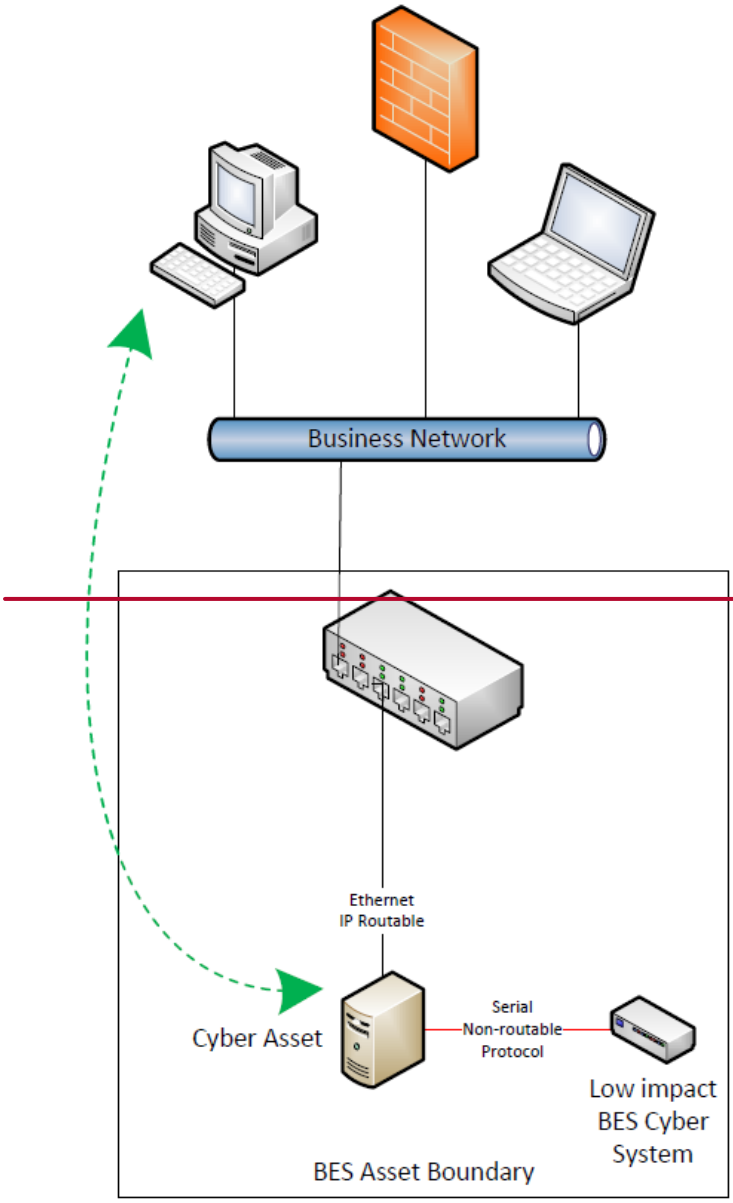


Data Flows

REFERENCE MODEL - 4

The low impact BES Cyber System is externally accessible from a Cyber Asset outside the asset containing the low impact BES Cyber System. There is LERC because the IP/Serial converter is extending the communication between the business network Cyber Asset and the low impact BES Cyber System is directly addressable from outside the asset. A security device is placed between the business network and the low impact BES Cyber System to permit only necessary electronic access to the low impact BES Cyber System.

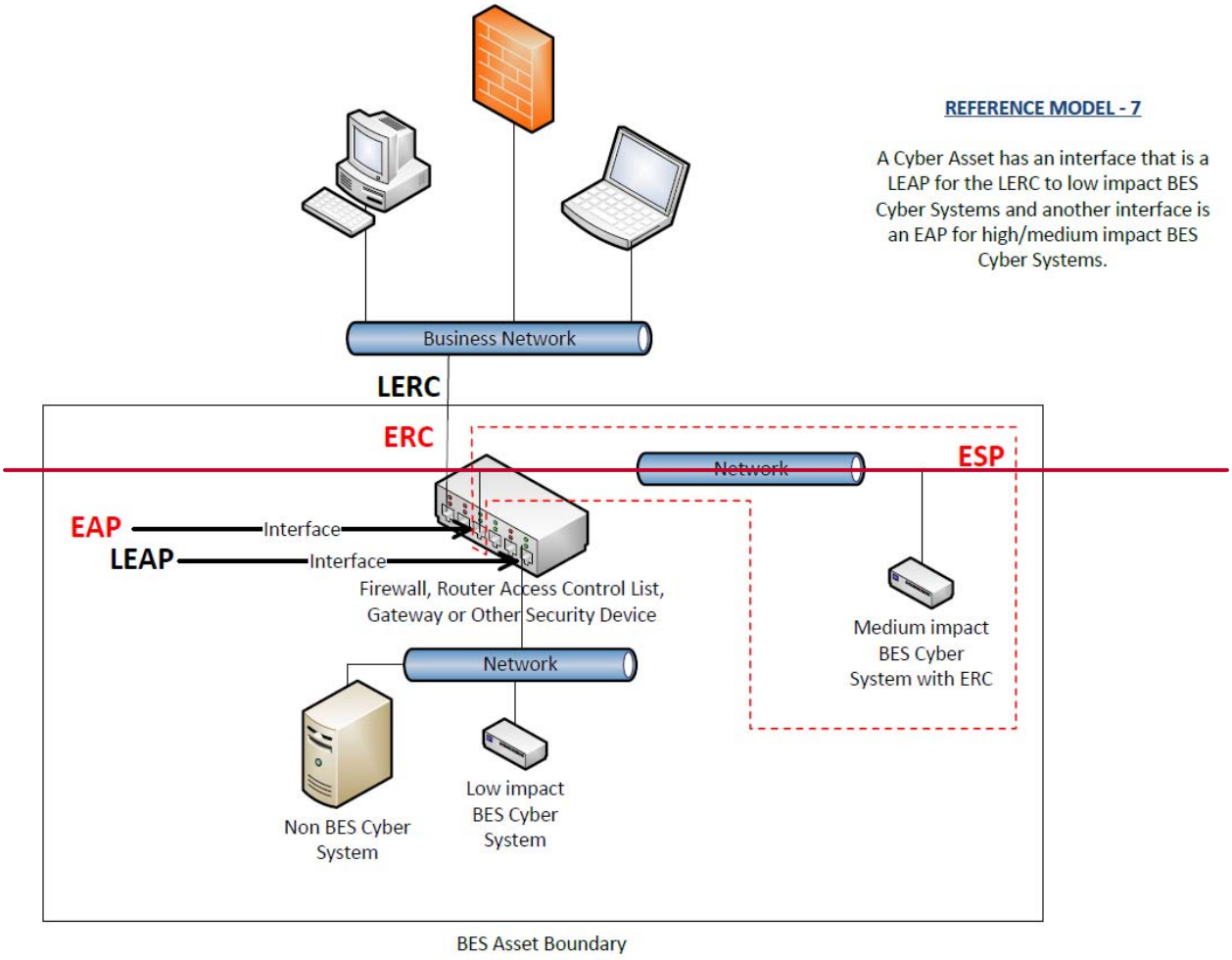

Data Flows
REFERENCE MODEL - 5
There is no bi-directional routable communications between low impact BES Cyber System(s) and Cyber Assets outside the asset containing those low impact BES Cyber System(s) therefore there is no LERC in this example.
Business Network
DMZ
Firewall, Router Access Control List, Gateway or Other Security Device
Network
Non-BES Cyber Asset (Non-routed, application layer separation of routable protocol sessions)
Low impact BES Cyber System
BES Asset Boundary



Data Flows

REFERENCE MODEL - 6

In this example, a Cyber Asset stops the direct access to the low impact BES Cyber System. There is a layer 7 application layer break or the Cyber Asset requires authentication and then establishes a new connection to the low impact BES Cyber System. There is no LERC in this example.



Requirement R2, Attachment 1, Section 4 – Cyber Security Incident Response

The entity should have one or more documented Cyber Security Incident response plan(s) that include each of the topics listed in Section 4. If, in the normal course of business, suspicious activities are noted at an asset containing low impact BES Cyber System(s), the intent is for the entity to implement a Cyber Security Incident response plan that will guide the entity in responding to the incident and reporting the incident if it rises to the level of a Reportable Cyber Security Incident.

Entities are provided the flexibility to develop their Attachment 1, Section 4 Cyber Security Incident response plan(s) by asset or group of assets. The plans do not need to be on a per asset site or per low impact BES Cyber System basis. Entities can choose to use a single enterprise-wide plan to fulfill the obligations for low impact BES Cyber Systems.

The plan(s) must be tested once every 36 months. This is not an exercise per low impact BES Cyber Asset or per type of BES Cyber Asset but rather is an exercise of each incident response plan the entity created to meet this requirement. An actual Reportable Cyber Security Incident

counts as an exercise as do other forms of tabletop exercises or drills. NERC-led exercises such as GridEx participation would also count as an exercise provided the entity's response plan is followed. The intent of the requirement is for entities to keep the Cyber Security Incident response plan(s) current, which includes updating the plan(s), if needed, within 180 days following a test or an actual incident.

For low impact BES Cyber Systems, the only portion of the definition of Cyber Security Incident that would apply is, "A malicious act or suspicious event that disrupts, or was an attempt to disrupt, the operation of a BES Cyber System." The other portion of that definition is not to be used to require ESPs and PSPs for low impact BES Cyber Systems.

Requirement R3:

The intent of CIP-003-~~6~~7, Requirement R3 is effectively unchanged since prior versions of the standard. The specific description of the CIP Senior Manager has now been included as a defined term rather than clarified in the Reliability Standard itself to prevent any unnecessary cross-reference to this standard. It is expected that the CIP Senior Manager will play a key role in ensuring proper strategic planning, executive/board-level awareness, and overall program governance.

Requirement R4:

As indicated in the rationale for CIP-003-~~6~~7, Requirement R4, this requirement is intended to demonstrate a clear line of authority and ownership for security matters. The intent of the SDT was not to impose any particular organizational structure, but, rather, the intent is to afford the Responsible Entity significant flexibility to adapt this requirement to its existing organizational structure. A Responsible Entity may satisfy this requirement through a single delegation document or through multiple delegation documents. The Responsible Entity can make use of the delegation of the delegation authority itself to increase the flexibility in how this applies to its organization. In such a case, delegations may exist in numerous documentation records as long as the collection of these documentation records shows a clear line of authority back to the CIP Senior Manager. In addition, the CIP Senior Manager could also choose not to delegate any authority and meet this requirement without such delegation documentation.

The Responsible Entity must keep its documentation of the CIP Senior Manager and any delegations up-to-date. This is to ensure that individuals do not assume any undocumented authority. However, delegations do not have to be re-instated if the individual who delegated the task changes roles or the individual is replaced. For instance, assume that John Doe is named the CIP Senior Manager and he delegates a specific task to the Substation Maintenance Manager. If John Doe is replaced as the CIP Senior Manager, the CIP Senior Manager documentation must be updated within the specified timeframe, but the existing delegation to the Substation Maintenance Manager remains in effect as approved by the previous CIP Senior Manager, John Doe.

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:

One or more security policies enable effective implementation of the requirements of the cyber security Reliability Standards. The purpose of policies is to provide a management and governance foundation for all requirements that apply to a Responsible Entity's BES Cyber Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the requirements.

Annual review and approval of the cyber security policies ensures that the policies are kept-up-to-date and periodically reaffirms management's commitment to the protection of its BES Cyber Systems.

Rationale for Requirement R2:

In response to FERC Order No. 791, Requirement R2 requires entities to develop and implement cyber security plans to meet specific security control objectives for assets containing low impact BES Cyber System(s). The cyber security plan(s) covers four subject matter areas: (1) cyber security awareness; (2) physical security controls; (3) electronic access controls; and (4) Cyber Security Incident response. This plan(s), along with the cyber security policies required under Requirement R1, Part 1.2, provides a framework for operational, procedural, and technical safeguards for low impact BES Cyber Systems.

Considering the varied types of low impact BES Cyber Systems across the BES, Attachment 1 provides Responsible Entities flexibility on how to apply the security controls to meet the security objectives. Additionally, because many Responsible Entities have multiple-impact rated BES Cyber Systems, nothing in the requirement prohibits entities from using their high and medium impact BES Cyber System policies, procedures, and processes to implement security controls required for low impact BES Cyber Systems, as detailed in Requirement R2, Attachment 1.

Responsible Entities will use their identified assets containing low impact BES Cyber System(s) (developed pursuant to CIP-002) to substantiate the sites or locations associated with low impact BES Cyber System(s). However, there is no requirement or compliance expectation for Responsible Entities to maintain a list(s) of individual low impact BES Cyber System(s) and their associated cyber assets or to maintain a list of authorized users.

Rationale for Requirement R3:

The identification and documentation of the single CIP Senior Manager ensures that there is clear authority and ownership for the CIP program within an organization, as called for in Blackout Report Recommendation 43. The language that identifies CIP Senior Manager responsibilities is included in the Glossary of Terms used in NERC Reliability Standards so that it may be used across the body of CIP standards without an explicit cross-reference.

FERC Order No. 706, Paragraph 296, requests consideration of whether the single senior manager should be a corporate officer or equivalent. As implicated through the defined term, the senior manager has "the overall authority and responsibility for leading and managing implementation of the requirements within this set of standards" which ensures that the senior manager is of sufficient position in the Responsible Entity to ensure that cyber security receives the prominence that is necessary. In addition, given the range of business models for

responsible entities, from municipal, cooperative, federal agencies, investor owned utilities, privately owned utilities, and everything in between, the SDT believes that requiring the CIP Senior Manager to be a “corporate officer or equivalent” would be extremely difficult to interpret and enforce on a consistent basis.

Rationale for Requirement R4:

The intent of the requirement is to ensure clear accountability within an organization for certain security matters. It also ensures that delegations are kept up-to-date and that individuals do not assume undocumented authority.

In FERC Order No. 706, Paragraphs 379 and 381, the Commission notes that Recommendation 43 of the 2003 Blackout Report calls for "clear lines of authority and ownership for security matters." With this in mind, the Standard Drafting Team has sought to provide clarity in the requirement for delegations so that this line of authority is clear and apparent from the documented delegations.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2016-02 Modifications to CIP Standards
Reliability Standard CIP-003-7 Security Management Controls and Low Impact External Routable Communication (LERC)

Requested Approvals

- Reliability Standard CIP-003-7 - Cyber Security – Security Management Controls
- ~~Definition of Low Impact External Routable Communication (LERC)~~

Requested Retirements

- Reliability Standard CIP-003-6 - Cyber Security – Security Management Controls
- Definition Low Impact BES Cyber System Electronic Access Point (LEAP)
- Definition of Low Impact External Routable Connectivity (LERC)

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Interchange Coordinator or Interchange Authority
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Background

On January 21, 2016, the Federal Energy Regulatory Commission (Commission) issued Order No. 822, *Revised Critical Infrastructure Protection Reliability Standards,* approving seven Critical Infrastructure Protection (CIP) Reliability Standards and new or modified definitions. In addition to approving the seven CIP Reliability Standards, the Commission, among other things, directed NERC to modify the definition of LERC. The Commission stated:

> 73. Based on the comments received in response to the NOPR, the Commission concludes that a modification to the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6 is necessary to provide needed clarity to the definition and eliminate ambiguity surrounding the term "direct" as it is used in the proposed definition. Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule. We agree with NERC and other commenters that a suitable means to address our concern is to modify the Low Impact External Routable Connectivity

definition consistent with the commentary in the Guidelines and Technical Basis section of CIP-003-6.

~~In addition~~As an alternative to modifying the definition consistent with the Commission's directive, the standard drafting team ~~revised the term "LERC" by replacing the word "connectivity" with the word "communication" such that the proposed term for inclusion in the Glossary of Terms used in NERC Reliability Standards (NERC Glossary) is "Low Impact External Routable Communication."~~retired the term "LERC" and incorpored the LERC concepts within the requirement language.

Given the ~~modified~~ proposed retirement of the LERC definition ~~of LERC~~ and the proposed modifications in Reliability Standard CIP-003-7, there is no longer a need for the NERC Glossary term Low Impact BES Cyber System Electronic Access Point (LEAP). Consequently, NERC is proposing to retire the term LEAP.

General Considerations

~~This Implementation Plan does not modify the~~ The effective ~~date for~~ dates or phased-in compliance dates within the CIP-003-6 ~~in the~~ Implementation Plan ~~associated with CIP-003-6 nor any of~~, remain in effect except that the ~~phased in~~ compliance dates for CIP-003-6, Requirement R2, Attachment 1, Sections 2 and 3 shall be replaced with the effective date of CIP-003-7.

The Responsible Entity shall not be required to include in its cyber security plan(s) elements related to Sections 2 and 3 of Attachment 1 until the effective date of CIP-003-7. Upon the effective date of CIP-003-7, the Responsible Entity's cyber security plan(s) must include the elements required by Sections 2 and 3 of Attachment 1 and the Responsible Entity must implement the controls included ~~therein~~in its plan to meet the objectives of Sections 2 and 3.

Effective Date

The effective date for the proposed Reliability Standard ~~and NERC Glossary term~~ is provided below:

Where approval by an applicable governmental authority is required, Reliability Standard CIP-003-7 ~~and the NERC Glossary term *Low Impact External Routable Communication* (LERC)~~ shall become effective on the later of September 1, 2018 or the first day of the first calendar quarter that is ~~nine (9~~twelve (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, Reliability Standard CIP-003-7 ~~and the NERC Glossary term *Low Impact External Routable Communication* (LERC)~~ shall become effective on the first day of the first calendar quarter that is ~~nine (9~~twelve (12) calendar months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Planned or Unplanned Changes

Planned or Unplanned Changes Resulting in a Higher Categorization – This implementation Plan incorporates by reference the section in the Implementation Plan associated with CIP-003-5 titled Planned or Unplanned Changes Resulting in a Higher Categorization.[1]

Unplanned Changes Resulting in Low Impact Categorization – This implementation Plan incorporates by reference the section in the Implementation Plan associated with CIP-003-6 titled Unplanned Changes Resulting in Low Impact Categorization. That section provides:

> For unplanned changes resulting in a low impact categorization where previously the asset containing BES Cyber Systems had no categorization, the Responsible Entity shall comply with all Requirements applicable to low impact BES Cyber Systems within 12 calendar months following the identification and categorization of the affected BES Cyber System.

Retirement Date

Reliability Standard CIP-003-6

Reliability Standard CIP-003-6 shall be retired immediately prior to the effective date of Reliability Standard CIP-003-7 in the particular jurisdiction in which the revised standard is becoming effective.

Current NERC Glossary of Terms of LERC and LEAP

The current definition of LERC and the term LEAP shall be retired from the NERC Glossary of Terms immediately prior to the effective date of ~~the revised LERC term~~CIP-003-7 in the particular jurisdiction in which the definition is becoming effective.

[1] Due to the length of that section, it is not reproduced herein.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2016-02 – Modifications to CIP Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factor~~s~~ (VRF~~s~~) and violation severity levels (VSLs) for ~~each r~~Requirement R2 in proposed NERC Reliability Standard CIP-003-7 - Cyber Security — Security Management Controls~~Project 2016-02, Modifications to CIP Standards~~. ~~Each requirement is assigned a VRF and a VSL.~~ These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

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

Guideline (2) – Consistency within a Reliability Standard

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

Guideline (3) – Consistency among Reliability Standards

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

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

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

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

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

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

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

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

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

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

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

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

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

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

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

VRF Justifications for CIP-003-7, Requirement R2	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower was assigned to this requirement. Cyber security plans enable effective implementation of the CIP standard's requirements for low impact BES Cyber Systems. The purpose of plans is for entities to develop an approach involving multiple procedures to address a broad subject matter. Using a plan, Responsible Entities can implement common controls that meet requirements for multiple high, medium, and low impact BES Cyber Systems.
FERC VRF G1 Discussion Guideline 1 - Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2 - Consistency within a Reliability Standard	This requirement calls for the Responsible Entity to implement a documented cyber security plan that contains certain sections specified in Attachment 1. The VRF is only applied at the requirement level and the Requirement Parts are treated in aggregate. While the requirement specifies a number of sections, not necessarily parts, that must be included in the cyber security plan, the VRF is reflective of the plan as a whole. Therefore, the assigned VRF of Lower is consistent with the risk impact of a violation across the entire requirement for BES assets that contain low impact BES Cyber Systems.
FERC VRF G3 Discussion Guideline 3 - Consistency among Reliability Standards	This requirement maps from CIP-003-5, Requirement R1, which has an approved VRF of Medium but applies to Cyber Assets with an inherently lower risk; therefore, the proposed VRF is consistent.
FERC VRF G4 Discussion	Failure to properly implement the cyber security plan would not, under Emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state

VRF Justifications for CIP-003-7, Requirement R2	
Proposed VRF	**Lower**
Guideline 4 - Consistency with NERC Definitions of VRFs	or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G5 Discussion Guideline 5 - Treatment of Requirements that Co-mingle More than One Obligation	The cyber security plan requirement encompasses a number of subject matter areas for low impact BES Cyber Systems. The VRF is identified at the risk level represented by all of the plan areas in aggregate. Therefore, the VRF is consistent with the highest risk reliability objective contained in the requirement.

VSLs for CIP-003-7, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document cyber security awareness according to Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity implemented electronic access controls but failed to document its cyber security plan(s) for	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to reinforce cyber security practices at least once every 15 calendar months according to Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing	The Responsible Entity documented the physical access controls for its assets containing low impact BES Cyber Systems, but failed to implement the physical security controls according to Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for electronic access controls for its assets containing	The Responsible Entity failed to document ~~or~~and implement one or more cyber security plan(s) for its assets containing low impact BES Cyber Systems according to Requirement R2, Attachment 1. (R2)

electronic access controls according to Requirement R2, Attachment 1, Section 3. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document one or more Cyber Security Incident response plans according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented one or more Cyber Security Incident response plans within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to update each Cyber Security Incident response plan(s) within 180 days according to Requirement R2, Attachment 1, Section 4. (R2)	low impact BES Cyber Systems, but failed to document physical security controls according to Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document electronic access controls according to Requirement R2, Attachment 1, Section 3. (R2) OR The Responsible Entity documented its cyber security plan(s) for electronic access controls but failed to implement authentication for all Dial-up Connectivity that provides access to low impact BES Cyber System(s), per Cyber Asset capability according to Requirement R2, Attachment 1, Section 3.2 (R2) OR The Responsible Entity documented one or more incident response plans within its cyber security plan(s) for its	low impact BES Cyber Systems, but failed to permit only necessary inbound and outbound electronic access controls according to Requirement R2, Attachment 1, Section 3.1. (R2) OR The Responsible Entity documented one or more Cyber Security Incident response plans within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to test each Cyber Security Incident response plan(s) at least once every 36 calendar months according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented the determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident, but failed to notify the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2, Attachment 1, Section 4. (R2)	

	assets containing low impact BES Cyber Systems, but failed to include the process for identification, classification, and response to Cyber Security Incidents according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document the determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2, Attachment 1, Section 4. ~~OR~~ ~~The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document physical security controls according to~~	~~OR~~ ~~The Responsible Entity documented electronic access controls for its assets containing low impact BES Cyber Systems, but failed to implement the electronic access controls to low impact BES Cyber Systems according to Requirement R2, Attachment 1, Section 3. (R2)~~ ~~OR~~ ~~The Responsible Entity documented the physical access controls for its assets containing low impact BES Cyber Systems, but failed to implement the physical security controls according to Requirement R2, Attachment 1, Section 2. (R2)~~	

	~~Requirement R2, Attachment 1, Section 2. (R2)~~ ~~OR~~ ~~The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document electronic access controls according to Requirement R2, Attachment 1, Section 3. (R2)~~		

VSL Justifications for CIP-003-7, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously-approved Requirement R2, CIP-003-6. Therefore, the proposed VSLs do 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 use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

VSL Justifications for CIP-003-7, Requirement R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSLs are based on a single violation, and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	There is an incremental aspect to a violation of this requirement in that some measurable reliability benefit can be achieved if the Responsible Entity has documented cyber security plan(s) but fails to address one or more of the required sections of Attachment 1. A single failure of this requirement does not compromise network computer security.
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	The action of the requirement is to implement documented cyber security plan(s). Documentation of the plan(s) is required, but is not the primary objective of the requirement. Documentation is interdependent with the implementation of the plan in this case; as such, the VSL measures distance from compliance in terms of whether or not the Responsible Entity implemented all the required elements of the plan. The drafting team's intent is that this covers both documentation and implementation and, therefore, accounts for the interdependence of these tasks.

Consideration of Issues and Directives

Project 2016-02 Modifications to CIP Standards

Project 2016-02 Modifications to CIP Standards		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Based on the comments received in response to the NOPR, the Commission concludes that a modification to the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6 is necessary to provide needed clarity to the definition and eliminate ambiguity surrounding the term "direct" as it is used in the proposed definition. Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule. We agree with NERC and other commenters that a suitable means to address our concern is to modify the Low Impact External Routable Connectivity definition consistent with the commentary in the Guidelines and Technical Basis section of CIP-003-6.	FERC Order 822, Paragraph 73; issued January 21, 2016	The Project 2016-02 Standard Drafting Team (SDT) ~~revised~~resolved the ambiguity identified by the Commission surrounding the term "direct" within the definition of ~~the term~~ Low Impact External Routable Connectivity ~~to resolve the ambiguity surrounding the term "direct" identified by the Commission. In doing so,~~(LERC) by retiring the term and incorporating the ~~SDT changed~~LERC concepts within the ~~term to Low Impact External Routable *Communication* (LERC) and simplified~~requirement language. Retiring the ~~definition so that LERC is an attribute of an asset containing low impact BES Cyber Systems. As revised, LERC exists where there is routable protocol communication that crosses the asset boundary without regard to whether 'direct' or 'indirect' access may occur. The revised~~ LERC definition removes the dependency between the electronic access controls that may be in place and having those controls determine whether LERC exists or not. The SDT determined that indirect access, regardless of what kind of ~~'~~security break~~'~~ is in place causing it to be indirect, is another form of electronic access control that is intended to meet the same security objective. The SDT determined that the requirements should address the electronic access controls rather than having some controls

Project 2016-02 Modifications to CIP Standards		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		implied through the definition. In changing the approach, the SDT avoids overemphasis on identifying LERC and focuses emphasis on the security objective in the requirements. Therefore, for those assets containing low impact BES Cyber Systems ~~that have LERC~~as identified in CIP-002, the SDT changed the language in Attachment 1, Section 3.1 from requiring a Low Impact Electronic Access Point (LEAP) to requiring that electronic access controls be implemented to meet the security objective of permitting "only necessary inbound and outbound electronic access ~~to~~as determined by the Responsible Entity for any communications that are: i. between a low impact BES Cyber ~~Systems."~~ System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber system(s); ii. using a routable protocol when entering or leaving the asset containing the low impact BES Cyber System(s); and, iii. not used for time-sensitive protection or control functions between intelligent electronic devices (e.g. communications using protocol IEC TR-61850-90-5 R-GOOSE)." Additionally, the SDT updated and incorporated the exclusion language from the approved LERC definition into the requirement language and expanded the Guidelines and Technical Basis with numerous examples of electronic access

Project 2016-02 Modifications to CIP Standards		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		control concepts that accomplish ~~this~~the defined security objective. Given the ~~modified definition~~proposed retirement of LERC and the proposed modifications in Reliability CIP-003-7, there is no longer a need for the NERC Glossary term Low Impact BES Cyber System Electronic Access Point (LEAP). Consequently, the SDT proposed the term's retirement.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Summary of Proposed Revisions

Project 2015-09 Establish and Communicate System Operating Limits

Do not use this form for submitting comments. Use the electronic form to submit comments on **Project 2015-09 Establish and Communicate System Operating Limits** (SOL). The electronic form must be submitted by **8 p.m. Eastern, Friday, August 12, 2016.**

Additional information is available on the project page. If you have questions, contact Lacey Ourso, Standards Developer by email or phone at 404.446.2581.

Background Information regarding Project 2015-09 Establish and Communicate System Operating Limits

The Facilities Design, Connections, and Maintenance (FAC) Reliability Standards fulfill an important reliability objective for determining and communicating System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) used in the reliable operation of the Bulk Electric System (BES). The purpose of Project 2015-09 – Establish and Communicate System Operating Limits is to revise these requirements. Revisions are necessary to eliminate overlap with approved Transmission Planning (TPL) requirements,[1] enhance consistency with Transmission Operations (TOP)[2] and Interconnection Reliability Operations (IRO)[3] standards, and address other concerns in the existing FAC standards regarding the determination and communication of SOLs and IROLs. As outlined in the Standards Authorization Request (SAR), the scope of the standards development project includes development of new or revised requirements and/or NERC Glossary definitions to provide clarity and consistency for establishing SOLs and IROLs, and to address potential reliability issues resulting from application of the current NERC Glossary definitions for SOL and IROL.[4]

High-level Overview of Proposed Revisions to FAC Reliability Standards

In developing revisions to the FAC Reliability Standards and definitions related to SOL and IROL, the standard drafting team (SDT) has focused on alignment with how SOLs and IROLs are treated in the approved TOP and IRO Reliability Standards (enforceable beginning April 1, 2017). The SDT believes this shift is critical to align the approach for how the System is actually operated as a result of the wholesale

[1] *See*, TPL-001-4
[2] *See*, TOP-001-3, TOP-002-4, TOP-003-3
[3] See, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, IRO-017-1
[4] The SAR was sponsored and submitted by the Project 2015-03 -Periodic Review of System Operating Limit Standards periodic review team (PRT).

revisions to the TOP and IRO Reliability Standards and reflects the manner in which operations are currently conducted. Below is a detailed explanation of how the proposed revisions complement the TOP/IRO revisions. The proposed changes to the FAC standards support a more reliable, dynamic approach to operating within actual limits that exist on the system, as opposed to reliance on "operating limits" that were set well in advance.

Overview of How Proposed Revisions Align with Revised TOP and IRO Reliability Standards

The revisions proposed to the FAC standards were designed to work together with the approved TOP and IRO Reliability Standards. The combination of the proposed revisions to the FAC standards and the TOP and IRO Reliability Standards, including the defined terms contained in those standards (Operational Planning Analysis (OPA)[5], Real-time Assessment (RTA)[6], and Operating Plans) when executed together will result in maintaining reliable BES performance. Thus, it is imperative that your review of the proposed revisions to the FAC standards is conducted with a full understanding of how these standards will work together with the approved TOP and IRO Reliability Standards. The proposed FAC revisions standing alone will not provide a complete picture of how different functional entities will work together to establish the appropriate operational limits, and then actually operate to them.

Under the approved TOP and IRO Reliability Standards:

- TOP-002-4 Requirement R1 requires the TOP to have an OPA that will allow it to assess whether its planned operations for the next day will exceed any of its SOLs.
- TOP-002-4 Requirement R2 requires that the TOP have an Operating Plan to address potential "SOL exceedances" identified as a result of its OPA.
- TOP-001-3 Requirement R13 requires that the TOP perform a RTA at least once every 30 minutes.

[5] NERC Glossary defines Operational Planning Analysis (OPA) as, "An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" [NERC Glossary as of June 24, 2016]

[6] NERC Glossary defines Real-time Assessment (RTA) as, "An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) [NERC Glossary as of June 24, 2016]

- TOP-001-3 Requirement R14 requires that the TOP initiate its Operating Plan to mitigate an "SOL exceedance" identified as part of its Real-time monitoring or RTA.

For more information on the TOP/IRO revisions, please visit the Project 2014-03 Revisions to TOP/IRO Reliability Standards project page.

Overview of Proposed Revisions to FAC-011-3, FAC-014-2 and Defined Terms SOL and SOL Exceedance

As outlined in greater detail below, the SDT is proposing to revise the existing definition of SOL and create a new NERC Glossary definition for "SOL Exceedance." The new definitions support the conceptual distinction between operating practices and the SOL itself. The SOL is the actual set of Facility Ratings, System voltage limits, or stability limitations that are to be monitored for the pre- and post-Contingency state. How an entity operates to those SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by the entity. The revised definition of SOL and new definition of "SOL Exceedance" will work together with the future-enforceable TOP and IRO Reliability Standards, including the definitions of OPA, RTA and Operating Practices as follows:

- The TOP is required to have an OPA to assess whether its planned operations for the next day will exceed any of its SOLs (*see*, TOP-002-4, Requirement R1). If the OPA identifies potential SOL exceedances, the TOP is required to have an Operating Plan to address those potential SOL exceedances (*see*, TOP-002-4, Requirement R2).
- Additionally, the TOP is required to perform a RTA at least once every 30 minutes (*see*, TOP-001-3 Requirement R13). If the TOP identifies that an SOL is being exceeded in Real-time operations, the TOP will implement the mitigating strategies identified in its Operating Plan (*see*, TOP-001-3 Requirement R14).
- In other words, an "SOL Exceedance" is simply unacceptable system performance that must be mitigated in accordance with the action plan the TOP has laid out in its Operating Plan.
- A potential SOL Exceedance may be identified by an OPA, or an actual SOL Exceedance may be identified by an RTA.
- The Operating Plan can include specific Operating Procedures or more general Operating Processes. The TOP Operating Plans include both pre- and post- Contingency mitigation plans and strategies. The pre-Contingency strategies are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the Contingency. Post-Contingency mitigation plans and strategies are actions that the TOP will implement after the Contingency occurs to bring the system back within limits.
- The Operating Plans contain adequate details regarding the appropriate timelines to escalate the level of mitigation to ensure BES performance is maintained as required by the RC SOL Methodology.

The proposed definition of SOL Exceedance (described in further detail below) provides clarity regarding what is deemed to be "unacceptable system performance." When the conditions identified in the definition of SOL Exceedance occur, the TOP must be prepared

to implement its action plan outlined in its Operating Plan to mitigate that particular condition and return the system back within acceptable limits.

The SDT believes that the proposed definitions and revisions to the FAC standards will eliminate confusion between the operating practices used by the TOP and the actual limits themselves. The revisions provide clarity regarding (1) what the limits are, (2) what it means to exceed them, and (3) how an "SOL Exceedance" should be addressed by the TOP in operations planning (TOP-002-4 Requirement R2) and Real-time operations (TOP-001-3 Requirement R14).

Purpose of 30-day Informal Comment Period

As outlined above, the scope of Project 2015-09 includes revision of the requirements for determining and communicating SOLs and IROLs used in the reliable planning and operation of the BES. This informal 30-day posting does not encompass the entire scope of work that the SDT will undertake for the project. Rather, this is only a piece of the complete work. However, the SDT believes it to be the most critical area. The direction taken with regard to these standards set the foundation for building a proper SOL methodology to ensure that SOLs are established and communicated in a manner that will later ensure reliable BES operation when carried out in operations.

Reliability Standards and definitions that **are included** (as part of this limited, informal posting):

- FAC-011-3 – System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 – Establish and Communicate System Operating Limits
- Revisions to definition of System Operating Limit (SOL)
- New definition of SOL Exceedance

Reliability Standards and definitions that **are NOT included** (as part of this limited, informal posting):

- FAC-010-3 – System Operating Limits Methodology for the Planning Horizon
- Revisions to definition of Interconnection Reliability Operating Limit (IROL)
- Necessary revisions to existing Reliability Standards to incorporate concepts included in new defined term "SOL Exceedance" (*i.e.,* TOP-002-4 – capitalize SOL Exceedance to incorporate usage of defined term).

Although this is only an informal posting, the SDT underscores the importance of this posting. The SDT believes that the revisions proposed represent a significant improvement in how the industry works together to ensure reliability by establishing SOLs and operating to them in a manner that is reflective of the changing technology, and dynamic manner where entities have the ability to assess pre- and post-

Contingency performance in Real-time based on actual operating conditions. For these reasons, the SDT requests that commenters please take the time to review the background materials from the Project 2015-09 SOL Technical Conference which outline all of the various issues that were considered by the team, and discussed in an open forum with industry members. The SDT believes that we have captured the essence of the direction that the industry would like to take, but this is the opportunity for the team to continue to improve on proposed revisions by obtaining early feedback. The SDT looks forward to hearing and understanding your perspective for each of the very specific issues and associated questions raised below. In order for the SDT to thoroughly understand and incorporate your feedback into the future standard development, please do not simply provide yes or no responses. Please provide us with your perspective. Give us as much detail as you can. If you disagree with the SDT's direction, please provide an alternative approach that you believe will be superior to the one that the SDT proposed.

Proposed Revisions, Background Information and Questions

A. Definitions

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
System Operating Limits: Reliability limits used for operations, to include Facility Ratings, System voltage limits, and stability limitations.	The current definition of SOL (and the related FAC standards) presume an operating paradigm whereby a study or analysis is performed ahead of time to establish an SOL; the SOL is then communicated to operators; and the operators are given an operating plan to operate below the SOL with the presumption that doing so will result in acceptable pre- and post-Contingency system performance in Real-time operations. However, due to changes in the TOP and IRO Reliability Standards, along with advancements in technology from the time that the FAC standards were originally drafted, this is not reflective of how the system is actually operated. Today, entities continuously assess system performance and identify potential events in Real-time, based on *actual* operating conditions. The proposed revisions to the SOL definition, coupled with the proposed new definition of SOL Exceedance (see below) and the revisions to the FAC standards will support the concept that the SOL is the actual operating parameter; and eliminate confusion between "what the limits are" verses "how the system should be operated given the limits."	Existing definition of SOL: "The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings) • transient stability ratings (applicable pre- and post-Contingency stability limits) • voltage stability ratings (applicable pre- and post-Contingency voltage stability)

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	Given this shift, there is no need for the existing SOL definition language that includes concepts of "the most limiting criteria," "specified system configuration," "operation within acceptable reliability criteria," and "pre- and post-Contingency." These concepts are covered in the future-enforceable TOP and IRO Reliability Standards (including the defined terms contained therein: OPA, RTA, and Operating Plans), along with the proposed revisions to the FAC standards. As a result of the proposed revisions, the Facility Ratings, System voltage limits, and stability limitations are SOLs, all of the time, regardless of which one is "the most limiting." Also, as detailed below, the definition of "SOL Exceedance" will complement the revised definition of SOL by specifically identifying operating conditions that are deemed unacceptable, and require action by the TOP to mitigate. The proposed revisions use the term "stability limitation" rather than "transient stability limit," "voltage stability limit" or the Glossary term "Stability Limit." The intent of the SDT is that "stability limitation" is intentionally broad and can be used to encompass a number of different types of stability-related limitations or phenomenon, including, but not limited to, weighted short-circuit ratio (WSCR), sub-synchronous resonance (SSR), phase angle limitations, fault-interrupting capability of breakers, transient voltage limitations on equipment, and geomagnetic-induced currents on equipment. The Glossary term "Stability Limits" is not appropriate because it is limited to the maximum power flow value; this is too restrictive and not technology-neutral, as tools allow entities	• system voltage limits (applicable pre- and post-Contingency voltage limits)"

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	to monitor and control parameters other than maximum power flow values in order to demonstrate reliable stability performance. For more information regarding the proposed revisions to the SOL definition (and the definition of SOL Exceedance), please reference the Project 2014-03 – TOP and IRO Reliability Standards white paper entitled, "System Operating Limit Definition and Exceedance Clarification."	

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
SOL Exceedance: An operating condition characterized by any of the following: • Actual or pre-Contingency flow on a Facility is above the Normal Rating; • Calculated post-Contingency flow on a Facility is above the highest Emergency Rating;	As explained above, under the proposed revisions, the SOL is the actual set of Facility Ratings, System voltage limits, or stability limitations that are to be monitored for the pre- and post-Contingency state. How an entity remains within those SOLs will vary depending upon the particular Operating Plan of the entity. When the operating conditions listed in the definition of SOL Exceedance are identified – through an OPA or RTA – the TOP will take the actions outlined in its Operating Plan to mitigate the condition. The SDT did not include specific timing requirements for each condition listed in the definition, because the appropriate timing for operator response can vary depending upon the particular facts and	**Mapping to existing FAC standards or definitions under revision:** • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2)- Identifies performance requirements that RC SOL Methodology shall include. If the definition of SOL Exceedance is pursued by the SDT, the definition would be incorporated into existing standards that currently rely on the concept of an

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
• Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs; • Actual or pre-Contingency bus voltage is outside normal System voltage limits; • Calculated post-Contingency bus voltage is outside the emergency system voltage limits; • Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs; or, • Operating parameters indicate the next Contingency could result in instability.	circumstances. However, it is expected (and required) that the TOP Operating Plan specifically identify the allowable response time, along with the specific actions to be taken by the operator, in mitigating the condition. The bulleted items carry forward the types of limitations that are identified in the current definition of SOL, and incorporate the concepts of acceptable/unacceptable system performance, as currently contained in FAC-011-3 Requirement R2. For bullet item 3: This operating condition exists when the calculated post-Contingency flow falls below the highest Emergency Rating; however, the flow remains at a level where there is not sufficient time to reduce the flow to an acceptable level after the Contingency occurs. In this operating condition, the operator would be required to take pre-Contingency action, and could not rely on a post-Contingency mitigation plan. Because pre-Contingency action is required, the condition is deemed to be an "SOL Exceedance." For bullet items 4 and 5: Normal and emergency System voltage limits must respect the voltage limitations specified in the TO or GO Facility Ratings methodology (pursuant to FAC-008-3). Normal voltage limits are typically applicable for the pre-Contingency state, while emergency voltage limits are applicable for the post-Contingency state. "SOL Exceedance" with respect to these voltage	"SOL exceedance." The intent is not to change the meaning of the existing standards, rather the SDT believes that the proposed definition captures the existing meaning, but simply provides greater clarity through listing the specific types of conditions in the "SOL Exceedance" definition. In concert with proposing the new "SOL Exceedance" definition, the SDT would propose revisions (only as necessary) to existing standards to incorporate the newly defined Glossary term. Below are a few examples, but are not intended to represent a comprehensive or complete listing: • TOP-002-4 Requirement R1 - Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will result in an SOL Exceedance of its System Operating Limits (SOLs).

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
	limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event. Real-time Assessments recognize whether auto-reactive devices are sufficient for maintaining voltage within acceptable limits pre- or post-Contingency.	• TOP-002-4 Requirement R2 - Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) Exceedance(s) identified as a result of its Operational Planning Analysis as required in Requirement R1. • TOP-001-3 Requirement R14 - Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL Exceedance identified as part of its Real-time monitoring or Real-time Assessment.

B. Proposed Revisions to FAC-011-3

Proposed Reliability Standard: FAC-011-4, Requirement R1		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.	As outlined above, the SDT has incorporated the concepts contained in the existing FAC-011-3 Requirement R1 into the proposed revisions to the definitions of SOL and SOL Exceedance, along with the proposed revisions to FAC-011 and FAC-14. The existing Parts 1.1 through 1.3 are incorporated into the proposed new requirements, as detailed below.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1 – Sentence 1.

Proposed Reliability Standard: FAC-011-4, Requirement R2		
Proposed New/Revised Requirement	**Explanation / Rationale for Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and	Under FAC-008-3, Facility Ratings are established by Facility owners (TOs and GOs) consistent with the owner's methodology. These Facility Ratings are communicated to the RCs and TOPs. RCs and TOPs incorporate these ratings into their tools and processes and use the ratings in establishing their SOLs. Because TOs and GOs are not required to use any sort of continent-wide methodology for establishing the Facility	**Background regarding existing standards *not* under revision by SDT:** • FAC-008-3 Requirements R1, R2 and R3– GOs and TOs are required to have a methodology for developing Facility Ratings. • FAC-008-3 Requirement R6– GOs and TOs shall establish Facility Ratings consistent with its methodology.

Proposed Reliability Standard: FAC-011-4, Requirement R2		
Proposed New/Revised Requirement	**Explanation / Rationale for Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
the Transmission Operators in its Reliability Coordinator Area.	Ratings, it is possible for owners to use varying/different methodologies. This can create problems in establishing the appropriate SOL because the variations in Facility Rating methodologies may result in different or inconsistent types of Facility Ratings used in operations. If the RCs and TOPs are using different sets of Facility Ratings in conducting their respective outage coordination studies, OPAs, and RTAs, this may create a potential risk to reliability. The intent of Requirement R2 is for the RC SOL Methodology to identify the method that its TOPs will use in determining which of the Facility Ratings provided by the owner (under FAC-008-3) are appropriate for use in establishing SOLs for use in operations. As outlined above, under the revised definition of SOL, the Facility Ratings will be the SOL. The second sentence of Requirement R2 is intended to ensure that the RC and the TOP are using the same Facility Ratings, which will eliminate the risk identified above.	• FAC-008-3 Requirements R7 and R8– must provide their Facility Ratings to the RC, TOP and other functional entities. **Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1- RC SOL Methodology must state that SOLs shall not exceed associated Facility Ratings. • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2)- RC SOL Methodology shall include requirement that SOLs provide BES performance, and following certain prescribed conditions/states, remain within their Facility Ratings.

Proposed Reliability Standard: FAC-011-4, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable steady-state System voltage limits to be used in operations. The method shall: **3.1.** Require that System voltage limits are not outside of the Facility voltage ratings; **3.2.** Require that System voltage limits are not outside of voltage limits identified in Nuclear Plant Interface Requirements; **3.3.** Require that System voltage limits are above UVLS relay settings; **3.4.** Identify the lowest allowable System voltage limit; **3.5.** Address the use of common System voltage limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area; and,	There is no Reliability Standard that specifically requires establishment and communication of System voltage limits; however, System voltage limits are used in the definition of SOL and are an important aspect of reliable operations. The SDT believes it is important for the Reliability Standards to assign responsibility for the establishment and communication of System voltage limits. Like Facility Ratings, System voltage limits should be consistent between TOPs and RCs throughout all operations processes. The proposed Requirement R3 will result in the RC SOL Methodology requiring the TOP to determine System voltage limits for use in operations, consistent with the RC methodology.	**Background regarding existing standards *not* under revision by SDT:** • FAC-008-3 – Requires Facility Owner to establish Facility Ratings, which includes voltage ratings.[7] • VAR-001-4 Requirement R1 – The TOP specifies the system voltage schedule (which is either a range or a target value associated with a tolerance band) as part of its plan to operate within SOLs (and IROLs). **Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2) - RC SOL Methodology shall include requirement that SOLs provide BES performance with regard to certain prescribed conditions (pre-Contingency state, following certain identified single-

[7] Definition of Facility Ratings: The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Proposed Reliability Standard: FAC-011-4, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
3.6. Address coordination of System voltage limits between adjacent Transmission Operators in its Reliability Coordinator Area.		Contingencies) and remain within their thermal and voltage limits. [Proposed definitions of SOL and SOL Exceedance and Requirement R3 carry this forward.] • FAC-011-3 Requirement R1- RC SOL Methodology must state that SOLs shall not exceed associated Facility Ratings. [Proposed Part 3.1 carries this forward.] • Parts 3.2-3.6 were not clearly identified in the previous FAC standards; these are "new" requirements added by the SDT to provide clarity regarding steady-state system voltage limits.

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R4. Each Reliability Coordinator shall include in its SOL Methodology the method for	As detailed above, the existing definition of SOL provides that the SOL is "based upon" certain criteria, including transient stability ratings. The proposed	**Background regarding existing standards *not* under revision by SDT:**

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
determining the stability limitations to be used in operations. The method shall: **4.1.** Specify stability performance criteria for single Contingencies and for multiple Contingencies (as identified in Requirement R5), including any margins applied. The criteria shall consider the following: **4.1.1.** steady-state voltage stability; **4.1.2.** transient voltage response; **4.1.3.** angular stability; and, **4.1.4.** System damping. **4.2.** Require that stability limitations are established to meet the BES performance criteria specified in Part 4.1 for the following Contingencies: **4.2.1.** Loss of one of the following either by single phase or three phase Fault to ground with normal clearing, or without a Fault: • generator;	revisions to the SOL definition make clear that the SOLs "are" the reliability limits, which include stability limitations. Additionally, under the current standards, there are no set continent-wide stability limitations criteria for use in determining SOLs. Under existing FAC-011-3 Requirement R2, the RC has flexibility with regard to establishing stability limitations; provided the system performance requirements in the standard are met. While the existing language in Requirement R2 (and portions of Requirement R3) do provide some "continent-wide" uniformity, the requirements do not provide sufficient clarity regarding the distinction between establishing stability limitations and acceptable system performance requirements/response. The proposed revisions continue to allow the RC to have flexibility in its SOL Methodology for developing stability limitations. This ensures the RC is able to appropriately tailor the methodology to meet the particular needs of its system, since a "one size fits all" approach is not appropriate for stability limitations. However, the proposed requirement does set a number of minimum	• IRO-005-3.1a, Requirement R1 (Parts 1.2 and 1.3) – Each RC should monitor its RC Area parameters, including pre and post contingent element stability conditions. • IRO-008-2, Requirement R1 – Each RC shall perform an OPA that will assess whether next day planned operations will exceed SOLs or IROLs within its Wide-area. • MOD-001-2, Requirement R1 (Part 1.1) – Each TOP that calculates TFC or TTC shall have a written methodology that describes how those values are calculated, including the pre- and post-Contingency limitations for transient and voltage stability limits and other SOLs. **Mapping to existing FAC standards under revision:** • FAC-014-2, Requirement R6 (Parts 6.1 and 6.2) – Planning Authority shall provide multiple contingencies causing stability limits, and the limits, to the

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
• Transmission circuit; • transformer; • shunt device; • single pole of a direct current line. **4.2.2.** Loss of any multiple Contingencies identified in Requirement R5. **4.3.** Describe how instability risks are identified, considering realistic levels of transfers, Load and generation dispatch; **4.4.** Consider the stability limitations (and corresponding multiple Contingencies) provided by the Planning Coordinator in accordance with FAC-014-3 Requirement R8; **4.5.** Include a description of the study models, including the level of detail that is required and allowed uses of Remedial Action Schemes (RAS); and, **4.6.** Specify how stability limitations will be established when there is an impact to	required attributes (specific to stability limitations) that must be contained within the RC SOL Methodology. The proposed approach by the SDT is for the RC SOL Methodology to continue to set the method for how stability limitations for its RC Area must be established. Under proposed Requirement R4, the RC SOL Methodology must: Part 4.1 - Specify the stability performance criteria for single Contingencies and multiple Contingencies, including any margins applied. Part 4.2 - Meet the performance criteria for certain identified Contingencies (listed in the standard). Part 4.3 - Describe how instability risks are identified. The SDT changed the existing language of "anticipated" to "realistic." (See, FAC-011-3 Part 3.6) The SDT believes "anticipated" could be broadly interpreted to mean anticipated by the planners (in planning horizon), instead of what is realistically anticipated by the operators in the operations time horizon. Part 4.4 – Incorporates concepts from the existing FAC-011-3 Part 3.3, and requires the RC to consider the	Reliability Coordinator, or note to the RC if there are none. *[Maps to proposed Part 4.4]* • FAC-011-3 Requirement R2 (Part 2.1) - *[Maps to proposed Part 4.1, with new requirement providing specific types of criteria that must be considered.]* • FAC-011-3 Requirement R2 (Part 2.2) - *[Maps to proposed Part 4.2]* • FAC-011-3 Requirement R2 (Part 3.6) - *[Maps to proposed Part 4.3]* • FAC-011-3 Requirement R3 (Parts 3.1 and 3.5) – *[Maps to proposed Part 4.5]*

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
more than one TOP in its Reliability Coordinator Area.	stability limitations provided by the Planning Coordinator. Part 4.5 – This language combines some components of existing FAC-011-3 Parts 3.1, 4.3, and 3.5, but removes the blanket requirement for the study to include the entire RC Area. The revised language allows the RC to have flexibility to determine the appropriate study model, and required supporting details. Part 4.6 – The SDT believes that this Part will improve reliability by requiring the RC SOL Methodology to specify the appropriate manner to develop stability limitations, when those limitations impact more than one TOP in its RC Area. A companion requirement is FAC-014-3 Requirement R3, which requires the RC to determine the stability limitations when there is an impact to more than one TOP in its RC Area. (*See*, the proposed FAC-014-3 Requirement R3 for further explanation).	

Proposed Reliability Standard: FAC-011-4, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R5. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the multiple Contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation.	Currently effective Reliability Standard TOP-004-2 Requirement R3 requires the TOP operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its RC. This requirement was retired by the TOP/IRO project because it was addressed by the new TOP-001-3 Requirements R12 and R14 (which are not limited by single or multiple contingencies) in combination with existing FAC-011-3 Part 3.3 and FAC-014-2 Requirement R6 (which work collectively to establish how multiple Contingencies are considered in IROLs and SOLs). The proposed Requirement R5 maintains the existing approach that the RC SOL Methodology shall specify the multiple Contingencies for use in establishing stability limitations and IROLs. Further, it improves upon the existing requirement by allowing the RC SOL Methodology to identify multiple Contingencies beyond those identified by the planners.	**Background regarding existing standards *not* under revision by SDT:** • TOP-001-3 Requirements R12 and R14 **Mapping to existing FAC standards under revision:** • FAC-011-3 Part 3.3 • FAC-014-2 Requirement R6

Proposed Reliability Standard: FAC-011-4, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R6. Each Reliability Coordinator shall include in its SOL Methodology the method and criteria for establishing Interconnection Reliability Operating Limits (IROLs). The criteria shall describe the severity and extent of reliability impact that warrants establishment of an IROL, including: **6.1.** Unacceptable quantity of load loss due to System instability, Cascading outages or uncontrolled separation; **6.2.** Unacceptable quantity of supply loss due to System instability, Cascading outages or uncontrolled separation; **6.3.** Unacceptable thresholds for inter-area oscillations (including acceptable damping criteria and criteria for inter-area oscillations versus intra-area oscillations); and, **6.4.** Unacceptable impacts on neighboring Reliability	Regional differences exist in the criteria for determining which subset of SOLs are IROLs. The SDT discussed the regional differences among the various RC Areas, and several similarities emerged, including: (1) loss of load criteria, (2) loss of generation criteria, (3) non-localized or uncontained instability, and (4) impact on neighboring RC Area. The SDT evaluated the potential positive and negative impacts of creating continent-wide requirements, and determined that establishing minimum criteria that must be considered as part of the RC Methodology would benefit reliability; while continuing to allow necessary flexibility. The proposed language provides greater uniformity by identifying the criteria to be considered by the RC in establishing IROLs. The criteria must describe, at a minimum, the severity and extent of what is/not allowable with regarding to: (1) loss of load, (2) quality of supply loss, (3) thresholds for inter-area oscillations, and (4) impacts on neighboring RC Areas within its Interconnection. This minimum IROL criteria will provide for greater continent-wide consistency as it ensures all RCs consider and identify what is allowable for each criteria. The SDT believes while this does change the current state – where no mandatory minimum criteria exist- it still allows for the RC to have the necessary flexibility to design its IROL	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1 – RC SOL Methodology must include a description of how to identify the subset of SOLs that qualify as IROLs. • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL

Proposed Reliability Standard: FAC-011-4, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
Coordinator Areas within an Interconnection.	methodology so that it can meet the reliability issues present in, and possibly unique to, its RC Area.	

Proposed Reliability Standard: FAC-011-4, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R7. Each Reliability Coordinator shall include in its SOL Methodology the criteria for developing the IROL T_V for any IROLs in its Reliability Coordinator Area. Each IROL T_V shall be less than or equal to 30 minutes.	For the most part, the substance of this requirement is not changed from the existing standard; it was previously contained in a part (*i.e.,* FAC-011-3 Part 3.7) and is now a stand-alone requirement. The only change is that the 30 minute time-period is specifically identified, whereas in the previous requirement only stated T_v.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

Proposed Reliability Standard: FAC-011-4, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R8. Each Reliability Coordinator shall include in its SOL Methodology the method to address a Real-time operating state, where the next Contingency has the potential to cause System instability, Cascading outages or uncontrolled separation, but was not identified one or more days prior to the current day. The method shall address: **8.1.** Thresholds for initiating evaluation of potential impacts; **8.2.** A description of when pre-Contingency Load shedding is warranted to mitigate the condition; and, **8.3.** A review of the operating state experience for the purpose of determining whether an IROL should be established.	In Order No. 817, FERC noted that, "operators do not always foresee the consequences of exceeding such SOLs and thus cannot be sure of preventing harm to reliability." The SDT believes that in certain circumstances, such as in response to forced outages or similar unforeseen events, Real-time operating conditions can occur such that a RTA identifies an operating state where the next Contingency could result in instability, uncontrolled separation or Cascading outages. When this operating condition occurs in Real-time, it is clear that System Operator(s) are expected to take urgent action to mitigate the N-1 insecure operating state. What is unclear, however, is whether this operating condition constitutes some sort of an "IROL exceedance" or mandates that other IROL-related Reliability Standards should be applied. The proposed requirement requires the RC SOL Methodology to prescribe a method for how to address the above-described Real-time operating state. This will allow for consistency by System Operators within an RC Area in responding to the Real-time operating state when tools or analysis indicate abnormal post-Contingency conditions (*e.g.*, unsolved Contingencies, high post-Contingency overloads). While the requirement treats the operating state similar to, and equally important to, what prepared response must be	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL T_V.

Proposed Reliability Standard: FAC-011-4, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	in place for resolving an IROL-type issue, the requirement does not focus on formally establishing the limit, but instead allowing the System Operator to act with urgency to address the temporary operating state at hand. Also Part 8.3 requires the RC Methodology prescribe an after-the-fact review of the operating state experience for the purpose of determining whether an IROL should be established in accordance with the RC SOL Methodology.	

Proposed Reliability Standard: FAC-011-4, Requirement R9		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R9. Each Reliability Coordinator shall issue its SOL Methodology and any changes to the SOL Methodology, prior to the effective date, to: **9.1.** Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requested and indicated it has a reliability-related need for the SOL Methodology;	For the most part, the substance of this requirement is not changed from the existing standard. A clarification was added to Part 9.1 that RCs should issue its SOL Methodology, and any associated changes, to the other RCs *within* its Interconnection.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R4 – Requires the RC to issue its SOL Methodology, and any changes to the methodology, to its adjacent RCs and any RCs indicating a reliability-related need; to each PC and TP that models portions of its

Proposed Reliability Standard: FAC-011-4, Requirement R9		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
9.2. Each Planning Coordinator and Transmission Planner that models any portion of the Reliability Coordinator Area; and, **9.3.** Each Transmission Operator that operates in the Reliability Coordinator Area.		RC Area; and, each TOP that operates in its RC Area.

C. Proposed Revisions to FAC-014-3

Proposed Reliability Standard: FAC-014-3, Requirement R1		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area that are consistent with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.	The current FAC-014-2 Requirement R1 requires that the RC ensure SOLs and IROLs are established pursuant to its SOL Methodology. This creates a situation where the RC is responsible for "ensuring" actions out of its control. The proposed revisions do not change the intent of the standard –that the RC develop the SOL Methodology for establishing SOLs in its RC Area, and the TOP following the RC SOL Methodology in establishing those SOLs. Accordingly, the proposed Requirement R2 requires that the TOP establish SOLs as required by the RC SOL Methodology. The SDT believes this clarifies the appropriate responsibilities of the respective functional entities, while not creating ambiguity in the requirements in requiring the RC to do something that the TOP is, in all actuality, required to do. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R1 – Requires the RC to ensure SOLs and IROLs are establishing for its RC Area, consistent with its SOL Methodology. • FAC-014-2 Requirement R2 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R2		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R2. Each Transmission Operator shall establish SOLs for its portion of the Reliability Coordinator Area consistent with its Reliability Coordinator's SOL Methodology.	The SDT has removed language from the existing FAC-014-3 Requirement R2 that states the TOP, "shall establish SOLs (as directed by its Reliability Coordinator)" because it causes confusion and may be incorrectly understood to mean that the RC will issue a "Directive," or that TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and these SOLs must be established in accordance with (*i.e.*, pursuant to the "direction") identified in the RC's SOL Methodology.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R1 – Requires the RC to ensure SOLs and IROLs are establishing for its RC Area, consistent with its SOL Methodology. • FAC-014-2 Requirement R2 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R3. Each Reliability Coordinator shall determine stability limitations to be used in operations when the limitation impacts	The proposed approach by the SDT is that the RC SOL Methodology will set the method for how all stability limitations for its RC Area must be established (see, proposed	**Mapping to existing FAC standards under revision:**

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
more than one Transmission Operator in its Reliability Coordinator Area consistent with its SOL Methodology.	FAC-011-4 Requirement R4). The RC SOL Methodology must, among other things, specify the stability performance criteria for single Contingencies and multiple Contingencies, including any margins applied (see, proposed FAC-011-4 Part 4.1); meet the performance criteria for certain identified Contingencies listed in the standard (see, proposed FAC-011-4 Part 4.2); and describe how instability risks are identified (see, proposed FAC-011-4 Part 4.3). The TOP is required to establish stability limitation SOLs in accordance with everything outlined in the RC SOL Methodology. However, in addition to what is outlined above, the SDT believes that to the extent there are stability limitations that may impact more than one TOP in its RC Area, the RC should be responsible for determining these stability limitations (in accordance with its RC SOL Methodology – see, proposed FAC-011-4 Part 4.6). The purpose of providing a separate requirement for the RC to address this specific type of stability limitation is to provide clarity that there may be a stability limitation that is not appropriately labeled an "IROL," and thus, would not be covered by proposed Requirement R1. It is the position of the SDT that not all stability limitations are automatically "IROLs." For example, there may be instances of local, contained instability that are not appropriately designated	• N/A: This proposed requirement addresses what the SDT believes to be a gap in the existing requirements.

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	an "IROL," because labeling it as an IROL may require the TOP to take actions such as pre-Contingency load shedding, that is not warranted, and could actually cause a bigger reliability impact. However, when the stability limitation impacts more than one TOP, the SDT believes the RC should have primary responsibility for establishing that SOL.	

Proposed Reliability Standard: FAC-014-3, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R4. Each Reliability Coordinator shall provide the SOLs for its RC Area to adjacent Reliability Coordinators within an Interconnection and Reliability Coordinators who request and indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area. **4.1.** The Reliability Coordinators shall provide any updates to the SOL	The proposed Requirement R4 maintains the part of existing FAC-014-3 Requirement R5 which requires the TC to send the SOLs for its RC Area to adjacent RCs. The SDT has created a new/separate requirement related to communicating established IROLs (see proposed FAC-014-4 Requirement R5). The SDT added Part 4.1 to require the RC to provide updates to the SOLs to the impacted TOPs. It is expected that the RC and TOPs will establish a mutually agreeable means (pursuant to IRO-010-2 and TOP-003-3) for exchanging dynamically determined Facility Ratings or stability limitations.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R5 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
values established as part of Requirement R1 or Requirement R3 to impacted TOPs in its Reliability Coordinators Area in a mutually agreeable periodicity and format.		

Proposed Reliability Standard: FAC-014-3, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R5. Each Reliability Coordinator with an established IROL shall provide the following IROL information to adjacent Reliability Coordinators within an Interconnection, to other Reliability Coordinators that indicate a reliability-related need for the information, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area: **5.1.** Identification of the Facilities that are critical to the derivation of the IROL.	See above explanation. This requirement was previously combined with the requirement to provide updates to both SOLs and IROLs (existing FAC-014-3 Requirement R5). The SDT separated these into two requirements – one for SOL and one for IROL – so that greater detail could be provided regarding the type of IROL-information that must be communicated by the RC.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R5 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
5.2. The value of the IROL and its associated IROL T_V. **5.3.** The associated Contingency(ies). **5.4.** The type of limitation represented by the IROL (*e.g.*, voltage collapse, angular stability).		

Proposed New/Revised Requirement	Explanation of Proposed Revision	Relevant Requirements in Existing Reliability Standard(s)
R6. Each Reliability Coordinator with an established IROL shall provide the following IROL information to Transmission Owners and Generation Owners within its RC Area: **6.1.** Identification of the Facilities that are owned by that entity, which are critical to the derivation of the IROL.	In FERC Order No. 777, FERC directed NERC to develop a means to assure that IROLs are communicated to transmission owners (*see*, P6 and P41). The purpose of this proposed requirement is to address the concerns raised by FERC in Order No. 777. The RC is required to provide the IROL information identified in Part 6.1 to Transmission Owners and Generator Owners in its RC Area. The SDT included Generator Owners because it believes that GOs, in addition to TOs, need to receive information relating to facilities that are critical to the derivation of the IROL. The SDT did not combine this with proposed Requirement R5 because the team believes that the owners only need IROL information related to their facilities that are critical to the	**Mapping to existing FAC standards under revision:** • N/A: This proposed requirement is intended to address the issues raised in FERC Order No. 777.

Proposed New/Revised Requirement	Explanation of Proposed Revision	Relevant Requirements in Existing Reliability Standard(s)
	derivation of the IROL. However, the owners do not need the information identified in proposed Parts 5.2 through Part 5.4, and further, this information may contain sensitive operator information not appropriate for open-ended sharing.	

Proposed Reliability Standard: FAC-014-3, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R7. The Transmission Operator shall provide any SOLs and updates to those limits to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	The SDT did not make substantive changes to this requirement; however, the requirement previously existed as a "part" of a requirement and it is now a stand-alone requirement.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Part 5.2 – Requires the TOP to provide its SOLs to the RC and Transmission Service Providers in its portion of the RC Area.

Proposed Reliability Standard: FAC-014-3, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**

Proposed Reliability Standard: FAC-014-3, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R8. Each Planning Coordinator and Transmission Planner shall communicate the results of the stability analysis identified in its Planning Assessment and Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This shall include: **8.1.** The type of the instability (*e.g.*, voltage collapse, angular instability, transient voltage dip criteria violation); **8.2.** The Contingencies which result in the instability; **8.3.** Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss that was employed (or invoked) to address the instability; and, **8.4.** Any Corrective Action Plan associated with the instability.	Under proposed FAC-011-4 Part 4.4, the RC SOL Methodology must consider the stability limitations provided by the Planning Coordinator. Also, proposed FAC-014-3 Requirements R2 and R3, the applicable entities are required to establish stability limitations (if any) in accordance with the RC SOL Methodology. This requirement is intended to complement proposed FAC-011-4 Part 4.4 by ensuring that the planning entities provide the results of their stability analysis, including a list of those contingencies that are expected to produce the more severe System impacts, to the affected RC and TOP. This information may be relevant to the operating conditions for which the RC and TOP are determining SOLs. Further, FAC-013-2 requires that the PC have a methodology and annual assessment that identifies the weaknesses and limiting Facilities that could limit the ability of the Transmission System to reliably transfer energy. The results of the assessment, including the methodology used in the analysis, may contain information that may be relevant to the RC and TOP analysis for determining SOLs (and IROLs).	**Background regarding existing standards *not* under revision by SDT:** • TPL-001-4 • FAC-013-2 **Mapping to existing FAC standards under revision:** • FAC -011-3 Part 3.3 • FAC -014-2 Requirement R6

New or Modified Term(s) Used in NERC Reliability Standards

Glossary Term(s):

System Operating Limits: Reliability limits used for operations, to include Facility Ratings, System voltage limits, and stability limitations. ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

- ~~Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
- ~~transient stability ratings (applicable pre- and post- Contingency stability limits)~~
- ~~voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
- ~~system voltage limits (applicable pre- and post-Contingency voltage limits)~~

SOL Exceedance: An operating condition characterized by any of the following:

- Actual or pre-Contingency flow on a Facility is above the Normal Rating
- Calculated post-Contingency flow on a Facility is above the highest Emergency Rating
- Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs
- Actual or pre-Contingency bus voltage is outside normal System voltage limits
- Calculated post-Contingency bus voltage is outside the emergency system voltage limits
- Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs
- Operating parameters indicate the next Contingency could result in instability.

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A. Introduction

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

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

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

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

5. **Effective Date:** TBD

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.

R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable steady-state System voltage limits to be used in operations. The method shall:

3.1. Require that System voltage limits are not outside of the Facility voltage ratings;

3.2. Require that System voltage limits are not outside of voltage limits identified in Nuclear Plant Interface Requirements;

3.3. Require that System voltage limits are above UVLS relay settings;

3.4. Identify the lowest allowable System voltage limit;

3.5. Address the use of common System voltage limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area; and,

3.6. Address coordination of System voltage limits between adjacent Transmission Operators in its Reliability Coordinator Area.

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limitations to be used in operations. The method shall:

4.1. Specify stability performance criteria for single Contingencies and for multiple Contingencies (as identified in Requirement R5), including any margins applied. The criteria shall consider the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

4.2. Require that stability limitations are established to meet the BES performance criteria specified in Part 4.1 for the following Contingencies:

4.2.1. Loss of one of the following either by single phase or three phase Fault to ground with normal clearing, or without a Fault:

- generator;
- Transmission circuit;
- transformer;
- shunt device;
- single pole of a direct current line.

4.2.2. Loss of any multiple Contingencies identified in Requirement R5.

4.3. Describe how instability risks are identified, considering realistic levels of transfers, Load and generation dispatch;

4.4. Consider the stability limitations (and corresponding multiple Contingencies) provided by the Planning Coordinator in accordance with FAC-014-3 Requirement R8;

4.5. Include a description of the study models, including the level of detail that is required and allowed uses of Remedial Action Schemes (RAS); and,

4.6. Specify how stability limitations will be established when there is an impact to more than one TOP in its Reliability Coordinator Area.

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the multiple Contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation.

R6. Each Reliability Coordinator shall include in its SOL Methodology the method and criteria for establishing Interconnection Reliability Operating Limits (IROLs). The criteria shall describe the severity and extent of reliability impact that warrants establishment of an IROL, including:

6.1. Unacceptable quantity of load loss due to System instability, Cascading outages or uncontrolled separation;

6.2. Unacceptable quantity of supply loss due to System instability, Cascading outages or uncontrolled separation;

6.3. Unacceptable thresholds for inter-area oscillations (including acceptable damping criteria and criteria for inter-area oscillations versus intra-area oscillations); and,

6.4. Unacceptable impacts on neighboring Reliability Coordinator Areas within an Interconnection.

R7. Each Reliability Coordinator shall include in its SOL Methodology the criteria for developing the IROL T_V for any IROLs in its Reliability Coordinator Area. Each IROL T_V shall be less than or equal to 30 minutes.

R8. Each Reliability Coordinator shall include in its SOL Methodology the method to address a Real-time operating state, where the next Contingency has the potential to cause System instability, Cascading outages or uncontrolled separation, but was not identified one or more days prior to the current day. The method shall address:

8.1. Thresholds for initiating evaluation of potential impacts;

8.2. A description of when pre-Contingency Load shedding is warranted to mitigate the condition; and,

8.3. A review of the operating state experience for the purpose of determining whether an IROL should be established.

R9. Each Reliability Coordinator shall issue its SOL Methodology and any changes to the SOL Methodology, prior to the effective date, to:

9.1. Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requested and indicated it has a reliability-related need for the SOL Methodology;

9.2. Each Planning Coordinator and Transmission Planner that models any portion of the Reliability Coordinator Area; and,

9.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

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A. Introduction

1. **Title:** Establish and Communicate System Operating Limits

2. **Number:** FAC-014-3

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

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

   4.1.3. Planning Coordinator

   4.1.4. Transmission Planner

5. **Effective Date:** TBD

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area that are consistent with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.

R2. Each Transmission Operator shall establish SOLs for its portion of the Reliability Coordinator Area consistent with its Reliability Coordinator's SOL Methodology.

R3. Each Reliability Coordinator shall determine stability limitations to be used in operations when the limitation impacts more than one Transmission Operator in its Reliability Coordinator Area consistent with its SOL Methodology.

R4. Each Reliability Coordinator shall provide the SOLs for its RC Area to adjacent Reliability Coordinators within an Interconnection and Reliability Coordinators who request and indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area.

4.1. The Reliability Coordinators shall provide any updates to the SOL values established as part of Requirement R1 or Requirement R3 to impacted TOPs in its Reliability Coordinators Area in a mutually agreeable periodicity and format.

R5. Each Reliability Coordinator with an established IROL shall provide the following IROL information to adjacent Reliability Coordinators within an Interconnection, to other Reliability Coordinators that indicate a reliability-related need for the information, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area:

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5.1. Identification of the Facilities that are critical to the derivation of the IROL;

5.2. The value of the IROL and its associated IROL T_V;

5.3. The associated Contingency(ies); and,

5.4. The type of limitation represented by the IROL (*e.g.*, voltage collapse, angular stability).

R6. Each Reliability Coordinator with an established IROL shall provide the following IROL information to Transmission Owners and Generation Owners within its RC Area:

6.1. Identification of the Facilities that are owned by that entity, which are critical to the derivation of the IROL.

R7. The Transmission Operator shall provide any SOLs and updates to those limits to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R8. Each Planning Coordinator and Transmission Planner shall communicate the results of the stability analysis identified in its Planning Assessment and Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This shall include:

8.1. The type of the instability (*e.g.*, voltage collapse, angular instability, transient voltage dip criteria violation);

8.2. The Contingencies which result in the instability;

8.3. Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss that was employed (or invoked) to address the instability; and,

8.4. Any Corrective Action Plan associated with the instability.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Summary of Revisions to Reliability Functional Model

Functional Model Advisory Group

Background Information

Background regarding the Reliability Functional Model and Reliability Functional Model Technical Document

The Reliability Functional Model (FM) is a guideline that identifies the functions that must be performed to ensure that the Bulk Power System (BPS) is planned and operated in a reliable manner. The FM describes, in general terms, the functions that must be performed to ensure reliability, the specific tasks that are necessary to perform each function, and the relationships between functional entities that perform the various tasks. In its capacity of a guideline, the FM serves to provide a framework for NERC Reliability Standards as they are developed through the standard development process. The FM is independent of any particular organizational or market structure. The focus of the FM is solely on identification of reliability-related functions and the associated tasks and relationships. The FM is **not** a "standard" and does not have compliance effects. If there is a conflict between the FM and Reliability Standards, the Reliability Standards always take precedence. Also, the FM is **not** intended to identify the entities responsible for NERC registration. The NERC registration process is undertaken by NERC (and the Regional Entities) pursuant to authority from FERC, ultimately derived from the Federal Power Act. The FM has no authority, ability, or intent to impact or influence the NERC Registration process. The Reliability Functional Model Technical Document (FMTD) is a companion document to the FM. It serves to elaborate on the manner in which the various functional entities carry out their functions and perform their tasks.

Background regarding the Functional Model Advisory Group

The purpose of the Functional Model Advisory Group (FMAG), as outlined in the FMAG Scope document, is to (1) maintain the FM and FMTD to ensure the model correctly reflects the industry today, and (2) evaluate and incorporate new and emergent reliability-related tasks. The FMAG reports to the Standards Committee (SC), and works with the Planning Committee (PC), Operating Committee (OC), and Critical Infrastructure Protection Committee (CIPC) to obtain consensus regarding any proposed changes to the FM and FMTD. All proposed changes to the FM must be posted for industry comment, obtain consensus agreement from the PC, OC, and CIPC, and, ultimately, approval by the SC.

Overview of the 2016 FMAG project

In December 2015, the FMAG began a comprehensive review and assessment of the FM and FMTD to determine if it correctly reflects the industry today and whether there was a need to incorporate any new or emerging reliability-related tasks. As a result of the review, the FMAG identified many areas in need of revision. Below is a general summary of the type and nature of the revisions proposed by the FMAG.

General Overview of Proposed Revisions

1. Incorporated defined terms from the NERC Glossary of Terms: A large majority of the proposed revisions relate to incorporation of definitions from the NERC Glossary of Terms. For each proposed revision, the FMAG undertook a review to determine whether it was appropriate to incorporate the defined term, given the context and usage of the term in the FM. In some instances, the Glossary term was not used because the FMAG did not believe it had the intended meaning of the defined term, as used in the FM. In some instances, the term was simply capitalized to indicate it had the meaning of the Glossary term. In other instances, the word or phrase was replaced with a defined term (*i.e.*, reliability-related services replaced with Interconnected Operations Service).

2. Consolidated ERO-related functions: In the current version of the FM (version 5), there are separate functions for Standards Developer, Compliance Enforcement Authority and Reliability Assurance. The FMAG believes that all of these fall under one "function" of ensuring the reliability of the BPS. Therefore, all functions related to reliability assurance were moved to the Reliability Assurance function. The Reliability Assurance function is intended to include any tasks performed by the Electric Reliability Organization (ERO) to ensure the reliability of the BPS, including, for example, development of Reliability Standards, development and implementation of a compliance and enforcement program, and development and maintenance of a program for identifying and registering entities responsible for compliance.

3. Clarified the planning functions: Planning Coordinator (PC), Transmission Planner (TP), and Resource Planner (RP): The proposed revisions seek to identify the differences in the various planning functions, the tasks performed by the functional entities, and how the planners work together to ensure the Bulk Electric System (BES) has adequate reliability planning.

4. Clarified how Interchange occurs: The proposed revisions provide clarity regarding how the various functions and functional entities work together to perform Interchange, including incorporation of appropriate Glossary terms (*i.e.*, Requests for Interchange, Arranged Interchange, Confirmed Interchange).

5. Added cyber and physical security tasks: The FMAG is proposing to add two new tasks related to security protections for cyber assets and physical assets, and communication regarding an actual or suspected threat to those assets. The new tasks have been added to the following functions:

- Reliability Coordinator (RC)
- Balancing Authority (BA)
- Transmission Operator (TOP)
- Transmission Owner (TO)
- Interchange Coordinator (IC)
- Distribution Provider (DP)
- Generator Owner (GO)
- Generator Operator (GOP).

45-day informal comment period

The proposed revisions to the FM and FMTD are posted for a 45-day informal comment period. The FMAG will review all comments submitted and incorporate, as appropriate, proposed revisions to the FM and FMTD. In the documents posted for comment, the highlighted language is intended to indicate that the revision relates to a substantive change. The FMAG requests that you focus your comments on these highlighted revisions. Revisions that are not deemed substantive include revisions related to:

- Incorporation of a Glossary term;
- Clarification to the existing language (*i.e.*, use of consistent terminology);
- Changes to the order or manner of presentation of information (*i.e.*, rearrangement of tasks to follow a chronological order of how the tasks are performed);
- Consolidation of related items or removal of redundancies; and
- Changes to reflect how Interchange works, including incorporation of NERC Glossary terms.

Below is a mapping of the proposed revisions, along with an explanation of why the revision was needed necessary.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
1	General (Executive Summary, Introduction, Purpose, etc.)	Consolidated general background information and into one section (Section I – Purpose of the FM).	Provided clear, concise summary of the purpose of the FM; also, explained that the FM is a guideline and not a standard, nor does it identify entities for NERC Registration.
2	Standards Developer	Deleted entire section	See “Reliability Assurer” section

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
3	Compliance Enforcement Authority	Deleted entire section	See "Reliability Assurer" section
4	Reliability Assurer	Revised section to include greater detail regarding the tasks performed by the ERO (and the Regional Entities).	Identified the various tasks performed by NERC (and the Regional Entities) in its role as the ERO.
5	Planning Coordinator	Revised entire section to provide clarity regarding the differences in roles and tasks performed by the planning entities (*i.e.*, Planning Authority, TP, and RP). Also, provided greater clarity regarding how the planners work together to ensure the BES has adequate reliability planning.	New Tasks 1, 2, 3 work together to outline the sequential process followed by the PC to conduct transmission system assessments. The component of "analysis and development of resource adequacy plans" was intentionally removed from the PC tasks. With regard to the assessments performed: • Both the TP and PC perform assessments to evaluate whether future transmission system performance will meet the minimum acceptable system performance requirements. However, the TP and PC may consider different system conditions (and BES facilities) in performing their respective assessments; this flexibility allows for studying a wider range of system conditions and allows for a more complete and comprehensive assessment of the BES. • TP assessment includes the collection of transmission assets over which the TP is responsible for planning ("TP Area"). • PC assessment includes the collection of transmission assets over which the PC is responsible for coordinating planning ("PC Area"). The PC Area is normally comprised of more than one TP. The PC focuses on assessments of both Transmission and resource planning for its PC Area. • Every BES facility must have one associated TP and at least one PC. This means that every facility in the TP Area

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
			should be included in the assessment conducted by the TP.
6	Transmission Planner	Deleted Task No. 7: ~~Define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability needs.~~	The nature of the TP's work requires that the TP has an understanding of the "typical" system protection and control schemes utilized by the associated Transmission Owner(s). Through interaction with the TO, the TP can also have an influence on the system protection scheme standards that a TO uses. In some instances, the TP may recommend a Remedial Action Scheme (RAS) as a means of addressing Transmission system performance issues. The TP's awareness of, and influence on, system protection schemes were viewed as an integral part of the TPs' modeling and assessment tasks. The FMAG determined that a discussion of the TP's involvement with protection systems was better suited to the FMTD. Therefore the task was deleted.
7	Transmission Planner	Revised Relationship No. 9: Deleted "Resource Planner" and added "Planning Coordinator" "Submits and coordinates the plans for the interconnection of facilities to the Bulk Electric System within its Transmission Planner area with other Transmission Planners and the Planning Coordinator~~Resource Planners~~, as appropriate."	Removed "Resource Planner" and added "Planning Coordinator" because the PC is also concerned with transmission system assessments, whereas the RP is not.
8	Transmission Planner	Revised Relationship No. 10: Added "Planning Coordinator"	Added "Planning Coordinator" because of the PCs role and interest in assessing transfer capability.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		"Coordinates and develops transfer capability values with other Transmission Planners, Reliability Coordinators, Transmission Operators, Transmission Owners ~~and~~ Transmission Service Providers, and the Planning Coordinator."	
9	Resource Planner	Revised entire section to provide clarity and to distinguish resource planning tasks from other planning functions. Also, provided greater clarity regarding how the RPs interact with the TPs and Transmission Service Providers to ensure the BES has adequate resource planning.	Removed the prescriptive language to emphasize the completion of the task versus "how to perform" the task. Also, revised the language to improve clarity of the functional relationships.
10	Reliability Coordinator	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 11: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 12: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 11: Additional task necessary to identify RC reliability related responsibilities associated with cyber and physical security. New Task No. 12: Additional task necessary to identify RC communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
11	Reliability Coordinator	Revised Relationship No. 2: Added Distribution Providers	Added DP because the RC receives reliability-related facility and operational data from the DP.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		"Receives facility and operational data from Generator Operators, Distribution Providers, Load-Serving Entities, Transmission Owners, Generator Owners, and Transmission Operators."	
12	Reliability Coordinator	Revised Relationship No. 6: "Develop~~s~~ Interconnection Reliability Operating Limits, and provide them to those entities with a reliability-related need~~based on Transmission Owners' and Generator Owners' specified equipment ratings, and provides them to Transmission Operators~~."	Revised the relationship to reflect fact that RC establishes IROLs based on a number of factors (not limited to the equipment ratings); and the RC communicates the IROLs to various entities (not solely the TOP) based upon the specific requirements outlined in the RC's methodology or specific procedure in place.
13	Reliability Coordinator	Deleted Relationship No. 12: Duplicative ~~"Provide IROLs and TTC to the Transmission Service Provider for ATC calculation."~~	This is covered in Relationship No. 6.
14	Balancing Authority	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 14: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 15: "Communicate to appropriate authorities and relevant functional	New Task No. 14: Additional task necessary to identify BA reliability related responsibilities associated with cyber and physical security. New Task No. 15: Additional task necessary to identify BA communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		entities of an actual or suspected attack on cyber assets and/or physical assets."	
15	Balancing Authority	Added new Relationship: New Relationship No. 1: "Ahead of Time: Receive generator Facility plans from Generator Operators within the Balancing Authority Area."	Clarifies how and when information is provided from GOP in the BA Area.
16	Balancing Authority	Added new Relationship: New Relationship No. 2: "Ahead of Time: Receive operational data from Generator Operators within the Balancing Authority Area."	Clarifies how and when information is provided from the GO in the BA Area.
17	Balancing Authority	Deleted Relationship No. 2: Duplicative ~~"Receive operating and availability status of generating units from Generator Operators within the Balancing Authority Area."~~	Covered in Relationship No. 14
18	Balancing Authority	Revised Relationship No. 10: Removed GOP. "Implements generator commitment and dispatch schedules from the Load-Serving Entities ~~and Generator Operators~~ who have arranged for generation within the Balancing Authority Area."	Removed GOP because the information is from the LSE, not the GOP. The GOP operates the generator, the LSE has the schedule.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
19	Balancing Authority	Added new Relationship: New Relationship No. 1: "Receive reports on frequency regulating equipment from Generator Operators within the Balancing Authority Area."	Clarifies how and when information is provided associated with frequency regulation from the GOP in the BA Area.
20	Transmission Operator	Revised Task No. 8: "Adjust Real Power, Reactive Power and voltage ~~flow control devices within the transmission area~~ to maintain reliability."	Revised language to improve clarity regarding the task performed, while not limiting or specifying "how" the TOP maintains parameters to ensure reliability.
21	Transmission Operator	Deleted Task No. 9: Duplicative. ~~"Deploy reactive resources to maintain transmission voltage within defined limits."~~	Repeat of Task No. 8.
22	Transmission Operator	Added new Task: New Task No. 9: "Determine the Transmission capability that supports the Reliable Operation of the Transmission Operator Area."	Additional task supports the required Transmission capability assessments required to be completed by the TOP.
23	Transmission Operator	Added new Task: New Task No. 10: "Operate or direct the operation of Transmission Facilities in its TOP Area."	Additional task necessary to correctly identify the TOP responsibilities associated with the operation of the Transmission System.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
24	Transmission Operator	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 14: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 15: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 14: Additional task necessary to identify TOP reliability related responsibilities associated with cyber and physical security. New Task No. 15: Additional task necessary to identify TOP communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
25	Transmission Operator	Revised Relationship No. 11: "Ahead of time: Provides Total Transfer Capabilities, and System Operating Limits, and methodology for calculating to, and coordinates Available Transfer Capability for respective Transmission paths to with, Transmission Service Provider."	Revised language to improve clarity of the functional relationship.
26	Transmission Operator	Revised Relationship No. 12: "Ahead of time: Receives operating and availability status of generating units from Generatorion Operators including status of automatic voltage regulators and power system stabilizers."	Added "and power system stabilizers" to identify the need of the TOP to be aware of component status.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
27	Transmission Operator	Added new Relationship: New Relationship No.13: "Ahead of time: Receive operational data from Generator Operators."	Additional relationship necessary to ensure that the TOP has all necessary operational data to support Operations Planning functions and real-time contingency analysis.
28	Transmission Operator	Revised Relationship No. 18: "Real-time: Deploy~~s~~ reactive resources from Transmission Owners, ~~and~~ Generator Owners, and Distribution Providers to maintain acceptable voltage profiles."	Relationship expanded to include the DP as an operating authority for reactive resources.
29	Transmission Operator	Added new Relationship: New Relationship No.24: "Real-time: Receive Real-time operating information from Generator Operators."	Additional relationship necessary to ensure that the TOP has all necessary operational data to support real-time contingency analysis.
30	Interchange Coordinator	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 9: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 10: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 9: Additional task necessary to identify IC reliability related responsibilities associated with cyber and physical security. New Task No. 10: Additional task necessary to identify IC communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
31	Interchange Coordinator	Added new Relationship: New Relationship No. 7: "Receive reliability alerts from the Reliability Coordinators."	This was a missing reciprocal relationship to an existing RC relationship.
32	Transmission Service Provider	Revised Task No. 2: "Determine and post available transfer ~~capability~~ capacity values."	Changed capability to capacity to avoid Glossary conflict.
33	Transmission Service Provider	Added new Task: New Task No. 5: "Acquire Ancillary Services to support Transmission Service."	Added task to recognize provider of last resort responsibilities for required Ancillary Services to support Transmission Services in the Open Access Transmission Tariff.
34	Transmission Service Provider	Added new Task: New Task No. 6: "Update information that is relevant to a long-term Transmission Service arrangement."	Added task to support an existing reciprocal relationship with TP.
35	Transmission Service Provider	Added new Relationship: New Relationship No. 1: "Ahead of Time: Receive the methodology to determine available transfer capacity from the Transmission Operator."	Added relationship to recognize TOP responsibility to develop methodology.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
36	Transmission Service Provider	Revised Relationship No. 1: "Ahead of Time: Receive~~s~~ Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits from ~~Planning Coordinator,~~ the Transmission Planner, Transmission Operator and Reliability Coordinator, and coordinates ~~A~~available ~~T~~transfer capacity ~~Capability~~ with these entities and other Transmission Service Providers."	Deleted PC. Changed ATC to available transfer capacity to avoid Glossary conflict.
37	Transmission Service Provider	Revised Relationship No. 3: "Ahead of Time: Receive~~s~~ ~~t~~Transmission expansion plans identified by the Transmission Planner(s)~~Planning Coordinator~~ to help determine ability to accommodate long-term transmission service requests."	Changed PC to TP.
38	Transmission Service Provider	Added new Relationship: New Relationship No. 4: "Ahead of Time: Arrange for providers of Ancillary Services, and notify the Transmission Operator and Balancing Authority."	Supports newly added task to provider of last resort responsibilities for required Ancillary Services to support Transmission Services in the Open Access Transmission Tariff.
39	Transmission Service Provider	Added new Relationship:	Supports newly added task to provider of last resort responsibilities for required Ancillary Services to support Transmission Services in the Open Access Transmission Tariff.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		New Relationship No. 15: "Notify the Transmission Operator and Balancing Authority of changes to Ancillary Services."	
40	Transmission Owner	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 6: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 7: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 6: Additional task necessary to identify TO reliability related responsibilities associated with cyber and physical security. New Task No. 7: Additional task necessary to identify TO communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
41	Transmission Owner	Revised Relationship No. 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."	Deleted GO and LSE. Clarified scope.
42	Transmission Owner	Revised Relationship No. 9: "Develops interconnection agreements with the Distribution Providers and Generation Owners for connecting to the Bulk Electric System."	Deleted LSE.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
43	Distribution Provider	Revised Task No. 1: "Provide and operate electrical delivery ~~f~~Facilities between the ~~t~~Transmission system and the ~~E~~end-~~u~~Use ~~C~~customer or distribution-connected energy resource."	Added "distribution-connected energy resource" to recognize increasing number of these types of resources that impact the amount of energy supplied to the BES.
44	Distribution Provider	Added New Task: New Task No. 2: "Identify and characterize its connected load and energy resources."	DP should understand the characteristics of the load and resources connected to its system, which can have an impact on the BES performance.
45	Distribution Provider	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 7: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 8: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 7: Additional task necessary to identify DP reliability-related responsibilities associated with cyber and physical security. New Task No. 8: Additional task necessary to identify DP communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
46	Distribution Provider	Revised Relationship No. 1: "Ahead of time: Coordinate~~s~~ with Transmission Planners on interconnected load and energy	Added energy resources instead of only load.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		resources to support ~~t~~Transmission analysis~~expansion~~."	
47	Distribution Provider	Revised Relationship No. 3: "Ahead of time: Coordinate~~s~~ with ~~E~~end-use ~~C~~customers, distributed energy resources, and Load-Serving Entities to identify new ~~f~~Facility connection needs."	Added "distribution-connected energy resource" to recognize increasing number of these types of resources that impact the amount of energy supplied to the BES.
48	Distribution Provider	New Relationship added: New Relationship No. 7: "Ahead of time: Provide protective relaying systems, under-frequency Load shedding systems, under-voltage Load shedding systems, and Remedial Action Schemes as defined by the Transmission Planner and Planning Coordinator."	Relationship added to support existing Task No. 4
49	Distribution Provider	New Relationship added: New Relationship No. 8: "Real-time: Obtain voltage and power factor requirements from the Transmission Operator."	Relationship added to support existing Task No. 6
50	Generator Operator	Revised Task No. 5: "Support Interconnection frequency and voltage."	Accounted for GOP task of contributing to voltage support.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
51	Generator Operator	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 6: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 7: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 6: Additional task necessary to identify GOP reliability related responsibilities associated with cyber and physical security. New Task No. 7: Additional task necessary to identify GOP communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
52	Generator Operator	Revised Relationship No. 3: "Ahead of Time: Provide~~s~~ availability and operating ~~and availability~~ status of generator~~ing~~ Facilities~~units~~ to Reliability Coordinator, Balancing Authority and Transmission Operators for reliability analysis."	Added RC.
53	Generator Operator	Revised Relationship No. 4: "Ahead of Time: Report~~s~~ status of automatic voltage regulating equipment and power system stabilizer equipment ~~or frequency regulating equipment~~ to Transmission Operators."	Deleted frequency regulating equipment; added as a new task.
54	Generator Operator	Added new Relationship:	Added new Relationship to support existing Task.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		New Relationship No. 5: "Ahead of Time: Report on frequency regulating equipment to Balancing Authority."	
55	Generator Operator	Revised Relationship No. 5: "Ahead of Time: Provides operational data to Reliability Coordinator, Balancing Authority and Transmission Operator."	Added BA and TOP.
56	Generator Owner	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 5: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 6: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 5: Additional task necessary to identify GO reliability related responsibilities associated with cyber and physical security. New Task No. 6: Additional task necessary to identify GO communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
57	Generator Owner	Revised Relationship No. 2: "Provide~~s~~ Facility~~unit~~ maintenance schedules and ~~unit~~ generator Facility retirement plans to the Reliability Coordinator, Transmission Operator, Balancing Authority, Transmission Planner, and Resource Planner."	Added RC.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
58	Generator Owner	Revised Relationship No. 7: "Revises the generator~~ion~~ maintenance plans as requested by the Balancing Authority, Transmission Operator, and Reliability Coordinator."	Added BA and TOP.
59	Purchasing-Selling Entity	Added New Relationship No. 1: Arrange for energy and capacity from Generator Owners.	Added missing reciprocal relationship for Task No. 1.
60	Load-Serving Entity	Revised Task No. 3: "Identify and communicate ~~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."	Added communication element.
61	Load-Serving Entity	Revised Relationship No. 1: "Ahead of Time: Submit~~s~~ load data~~profiles and characteristics, plans, and forecasts~~ as needed to the appropriate entity (*e.g.*, Balancing Authorities, ~~Purchasing-Selling Entities, Planning Coordinator,~~ Resource Planners, and Transmission Service Providers~~Planners~~) in	Link the load data submission need and types to applicable tariff, interconnection agreements or other arrangements as opposed to a generic set.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		accordance with applicable tariffs, interconnection agreements or other arrangements."	
62	Load-Serving Entity	Revised Relationship No. 2: "Ahead of Time: Coordinate with Distribution Provider to identify critical loads that are to be excluded from load-sheddingIdentifies new facility connection needs for End-use Customers."	Clarify that the DP is the entity impacted by the identified information.
63	Load-Serving Entity	Revised Relationship No. 12: "Real-time: Receives requests from the Reliability Coordinator, Balancing Authority, Transmission Operator, and Distribution Provider for voluntary load cCurtailment."	Added RC and TOP, who also make these requests.
64	Load-Serving Entity	Revised Relationship No. 13: "Real-time: Communicate requests for voluntary load cCurtailment to end-use customers as directed by the Reliability Coordinator, Balancing Authority, Transmission Operator and Distribution Provider."	Added RC and TOP, who also make these requests.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Functional Model Technical Document

Version 6~~5~~

Prepared by the Functional Model Advisory Group
Approved by the Standards Committee: [Month, Year]

RELIABILITY | ACCOUNTABILITY






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Introduction

The Functional Model Technical Document (FMTD) ~~This document~~ is intended as a companion to Version ~~5~~ 6 of the Functional Model to help explain the functions, including the functional entities, the respective tasks performed by each functional entity, and the relationships with other functional entities that are necessary to perform the tasks. ~~the reader better understand the Model's Functions, functional entities and their relationships. This document therefore provides context, explanation and opinions. It is a companion to, rather than a formal part of, Version 5 of the Model.~~

Section I – Functional Entity Tasks and Interrelationships provides details regarding the functional entity tasks and interrelationships. ~~about each of the Responsible Entities.~~ A number of the ~~Some~~ functional entities, such as the Transmission Owner or Purchasing-Selling Entity, are adequately described in the FM~~unctional Model document~~, so~~and~~ there is no need to provide further ~~little~~ detail in the FMTD~~to add here~~. Other entities, such as the Interchange Coordinator and Balancing Authority, are more complex, including their ~~both unto themselves and in their~~ relationships with other functional entities, and the FMTD ~~is document~~ provides further explanation regarding how these entities work together to ensure reliability~~additional explanations~~.

Section II – Technical Discussion includes technical discussions on related topics such as managing Arranged and Confirmed Interchange, and functional entity areas and boundaries~~y conditions~~. ~~The discussion of Market Operations illustrates that the Model applies to different market structures.~~

SECTION I – FUNCTIONAL 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 Functional 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 Functional Model Working Group that having two different contexts for responsibility did not completely eliminate the potential for confusion. On this basis, Version 5 goes one step further and eliminates reference to responsibility within the Model, replacing the term responsible entity with the term functional entity. In Version 5 of the Model, an entity is defined by the functions it performs.[1]~~

~~As a result of refocusing the Model on Tasks rather than responsibility, Version 5 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 the NERC Rules of Procedure. These include situations where:~~

- ~~an organizations may "bundle" a number of different functions and register as the corresponding functional entities, for example Reliability Coordinator and Transmission Operator~~
- ~~two or more organizations may register jointly with NERC as functional entities and thereby divide or share responsibility for meeting standards requirements (Joint Registry Organizations)~~
- ~~an organization may register and assume responsibility for Tasks performed by others, such as a rural cooperative on behalf of its members.~~

~~[1] Version 5 of the Model uses the term "functional entity" to apply to the *entity described in the Functional 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 functional entity.~~

Part 1 - Reliability Coordinator

The Reliability Coordinator~~'s~~ purview must be broad enough to enable it to ~~calculate~~ establish Interconnection Reliability Operating Limits, which will involve ~~s~~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 monitoring for and 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 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 has final authority in coordination and resolution of conflicts regarding transmission and generation outage requests. The Reliability Coordinator can deny a transmission outage request and some elective, generation outage requests 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 establishing and 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~~ exceedance and issue a dispatch adjustment. Therefore, in this context, the Reliability Coordinator also has a role regarding the Transmission Operator's management of SOL exceedances.

Emergency actions. The Reliability Coordinator is responsible for Real-time system reliability, which includes calling for the following emergency actions:

- Curtailing Interchange Schedules
- Directing re-dispatch to alleviate congestion or other SOL exceedances

- Mitigating energy and transmission emergencies
- Ensuring energy balance and Interconnection frequency
- Directing load shedding.

The Reliability Coordinator, in collaboration with the Balancing Authority and Transmission Operator, can invoke public appeals, voltage reductions, ~~d~~Demand-~~s~~Side ~~m~~Management, Energy Emergency alerts, and even load shedding if the Balancing Authority cannot achieve resource-demand balance.

System restoration actions. The Reliability Coordinator directs and coordinates ~~system~~ restoration of the BES for its RC Area, with Transmission Operators, ~~and~~ Balancing Authorities and other Reliability Coordinators.

~~**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 SOL exceedances, delineation of its authority and that of the Transmission Operator needs to be clearly defined ~~in the reliability plan(s)~~.

Part 2 - Balancing Authority

The Balancing Authority operates within the metered boundaries that establish the Balancing Authority Area. Every generator, ~~t~~Transmission ~~f~~Facility, and end-use customer is in a Balancing Authority Area. The Balancing Authority's mission is to maintain the balance between ~~loads~~ Demand and resources in real time within its Balancing Authority Area by keeping its actual ~~i~~Interchange equal to its scheduled ~~i~~Interchange and meeting its ~~f~~Frequency ~~b~~Bias obligation. The demand~~load~~-resource balance is measured by the Balancing Authority's Area Control Error (ACE). In performing its balancing function, the Balancing Authority does not own the resources.

~~NERC's Reliability Standards require that t~~The Balancing Authority maintains its ACE within acceptable limits. Maintaining ~~resource-d~~Demand-resource balance within the Balancing Authority Area requires four types of resource management, all of which are the Balancing Authority's responsibility. Each of these resource management functions require sufficient resources provided to it by other entities:

- ~~F~~frequency control through tie-line bias
- Regulation ~~s~~Service deployment
- ~~L~~load-following through economic dispatch
- Interchange implementation

Frequency control through ~~t~~Tie-~~l~~Line ~~b~~Bias. To maintain frequency within acceptable limits, the Balancing Authority controls resources within its Balancing Authority Area to meet its ~~f~~Frequency ~~b~~Bias obligation to the ~~i~~Interconnection.

Regulation service deployment. To maintain its ACE within these acceptable limits, the Balancing Authority controls a set of generators within its Balancing Authority Area that are capable of providing ~~r~~Regulation ~~s~~Service.

Load-following through economic dispatch. The organization that serves as the Balancing Authority 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 receives Confirmed Interchange from one or more Interchange Coordinators, and enters those Interchange Schedules into its energy management system.

Unit commitment and schedules from Load-Serving Entities. The Balancing Authority receives resource dispatch plans from the Market Operator and/or unit commitment and dispatch ~~s~~Schedules from the Load-Serving Entities that have bilateral arrangements for generation within the market or the Balancing Authority Area. The Balancing Authority provides this commitment and dispatch ~~s~~Schedule to the Reliability Coordinator.

Role in approving Interchange. The Balancing Authority 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 provides its approval or denial to the Interchange Coordinator.

Energy Emergencies. In the event of an Energy Emergency, the Balancing Authority can implement public appeals, ~~d~~Demand-~~s~~Side ~~m~~Management programs, and, ultimately load shedding. Obviously, it must do this in concert with the Reliability Coordinator.

Failure to balance. The Balancing Authority must take action, either under its own initiative or direction by the Reliability Coordinator, if the Balancing Authority cannot comply with NERC's Reliability Standards regarding frequency control and Area Control Error.

~~See "Managing Bilateral Interchange Transactions"~~

Reserve Sharing Groups: In the past, only reserve sharing groups have been associated with Contingency Reserve. However, as the industry has evolved, additional commercial relationships between Balancing Authorities are occurring and thus creating new responsible groups. These responsible groups now include Regulation Reserve Sharing Groups, Frequency Response Sharing Groups, Frequency Response Sharing Groups and Contingency Reserve Sharing Groups. These groups are the responsible entities, but the Balancing Authorities remain responsible for performance within each respective group. The Balancing Authorities enter into commercial arrangements among themselves to form the respective sharing groups.

Part 3 - Planning Coordinator

The Planning Coordinator coordinates and integrates ~~t~~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~~ assessing~~of~~ expansion ~~reinforcement~~ and corrective action plans developed by the Transmission Planner(s) ~~functional 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~~. The assessment should consider the interaction of system changes under a range of selected scenarios across the entire Planning Coordinator area. The PC assessment includes the collection of Transmission assets over which the Planning Coordinator is responsible for coordinating planning ("PC Area"). The PC Area is normally comprised of more than one Transmission Planner; however, the area under the purview of a Planning Coordinator may include as few as one Transmission Planner. The Planning Coordinator's scope of activities is intended to span a broader area that may include BES assets of multiple Transmission Planners. All BES Facilities should be assigned to a Transmission Planner and to a Planning Coordinator, so that there are no gaps in the assessment of the BES.

Planning Coordinators work through a variety of processes to conduct facilitated, coordinated, joint, centralized, or regional planning activities to the extent that all portions of the interconnected BES are completely coordinated for planning activities. 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 inter- state 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 the function 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 facilities under the purview of the Planning Coordinator, *i.e.* those 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 facilities. The BES 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 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 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 ISOs and RTOs perform the Reliability Planning Functions but they are also under the purview of the Regional Entity that also performs the Reliability Planning Functions 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 function and scale (area-wise) of assessments performed. In order to ensure all BES Facilities are associated with a Planning Coordinator, clear delineation of the "PC Area" should establish the BES Facilities and associated connections to its adjacent Planning Coordinators. ~~In these cases, delineation of the role of the various functional entities needs to be clearly defined in the regional reliability plan(s).~~

The Planning Coordinator is not responsible for implementing the ~~t~~Transmission and resource plans. However, it helps to facilitate the process whereby adequate resources and ~~t~~Transmission ~~f~~Facilities are placed into service in a timely and efficient manner through coordinated planning with the ~~Resource Planners,~~ Transmission Planners~~, and possibly others through the coordinated planning process~~.

Part 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.[2] ~~area of purview.~~

The Transmission Planning function is typically associated with the Transmission Ownership function. The Transmission Planner performs the tasks of modeling, simulating and assessing the performance of the Transmission system under a range of future scenarios on a recurring basis. As Transmission system performance deficiencies are identified through this process, the Transmission Planner studies alternative solutions for correcting the deficiencies. Through interactions with various stakeholders, the Transmission Planner ultimately arrives at a recommended Corrective Action Plan that will resolve the identified deficiencies. For solutions that involve Transmission system capacity expansion, the associated Transmission Owner(s) is responsible for implementing the solution.

Both the Transmission Planner and Planning Coordinator perform assessments to evaluate whether future Transmission system performance will meet the minimum acceptable system performance requirements. The Transmission Planner and Planning Coordinator may consider different system conditions (and BES Facilities) in performing their assessments. This flexibility allows the Transmission Planner and Planning Coordinator to study a wider range of system conditions, which leads to a more complete and comprehensive assessment of the BES. For example, a Transmission Planner may set higher System performance criteria for a particular area under assessment.

The Transmission Planner assessment includes the collection of Transmission assets over which the Transmission Planner is responsible for planning ("TP Area"). The Planning Coordinator assessment includes the collection of Transmission assets over which the Planning Coordinator is responsible for coordinating planning ("PC Area"). The PC Area is normally comprised of more than one TP. Every Facility must have one associated Transmission Planner and at least one Planning Coordinator. This means that every Facility in the TP Area should be included in the assessment conducted by the TP.

As noted above, this typically aligns with the Transmission system facilities owned by an associated Transmission Owner(s). Because of the interconnected nature of the Bulk Electric System, the Transmission Planner works with other Transmission Planners to periodically update power system models used to perform simulations. Information needed to update these models is collected from various functional entities within a particular Transmission Planner's area of purview. Power system modeling data is also "rolled up" by the Transmission Planner(s) to the Planning Coordinator to support development of Interconnection level models.[3] ~~, *i.e.*, those facilities for which the Transmission Planner develops reinforcement and corrective action 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 interconnection wide models. The BES facilities in its area, *i.e.*, under its purview, are generally contiguous.~~

[2] Definition of Transmission Planner (effective July 1, 2016) from the NERC Glossary of Terms. In the Glossary, Planning Coordinator and Planning Authority are defined interchangeably.

[3] In some instances, the same entity may serve as both a Transmission Planner and Planning Coordinator.

~~Traditionally transmission planning has been associated with one or more Transmission Owners, *i.e.*, reinforcement and corrective action 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 Area while the remaining facilities may be in another. As such, the Transmission Planner Area is not constrained to fit within one Reliability Coordinator or Transmission Operator Area. However, the Transmission Planner 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 impact of ~~facilities that will be needed in response to~~ long-term ~~requests for t~~Transmission ~~s~~Service requests, and the ~~needed to~~ integration~~e~~ of new generation, ~~t~~Transmission, and end-use customers, ~~into the Bulk Electric Systems~~on the planned Transmission system performance. In evaluating requests ~~developing plans~~ for long-term ~~t~~Transmission ~~s~~Service or~~and~~ new interconnection~~s requests~~, the Transmission Planner is expected to coordinate ~~plans or engage in joint planning~~ with other Transmission Planners, as appropriate, to ensure new service/facilities do not adversely affect the reliability of neighboring ~~t~~Transmission systems.

~~Based on customer requests for transmission service, native load growth, changes in existing native load, and the planning procedures and protocols established for their Transmission Planning Areas, the Transmission Planners will develop transmission plans to accommodate long-term firm transmission service requests and native 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 assessment results ~~transmission plans~~ to ~~its~~ the appropriate Planning Coordinator for review to ensure that the impacts on the interconnected systems are duly addressed. In reporting its ~~transmission expansion plan~~assessment results to the Planning Coordinator, the Transmission Planner is expected to assess whether its plans for new or reinforced facilities meet reliability needs or whether corrective plans are necessary. The Transmission Planners work with the Planning Coordinator to identify potential alternative solutions, including solutions proposed by stakeholders, to meet interconnected Bulk Electric System requirements.

Part 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-side 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 function 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 functional entity. 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.

Part 6 - Transmission Operator

The Transmission Operator acts or authorizes action to connect to, disconnect from or reconfigure (switching operations) Facilities classified as Transmission assets, as described by the following:

a. Actions may include direct or indirect control of Transmission assets from a Control Center to conduct operations during Normal and Emergency conditions.

b. Authorizations to act may include orders directing designated field personnel with Transmission System switching responsibilities to perform switching operations on Facilities classified as Transmission assets during Normal and Emergency conditions.

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 ~~t~~Transmission system within its purview in a manner that maintains proper voltage profiles and System Operating Limits, and honors ~~t~~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 ~~s~~System restoration.

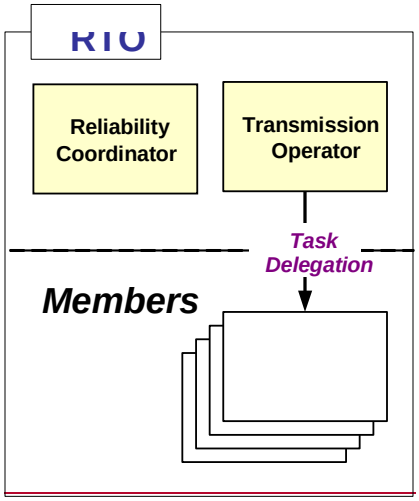
~~Note that the Model does not attempt to define what is and isn't a transmission facility, versus a generating facility. As discussed in Section II-13, this is assumed to be defined elsewhere by NERC or by governmental authorities.~~

~~**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 functional entity for multiple Functions. In such a case, the functional 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 functional 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 Tasks to its members.~~



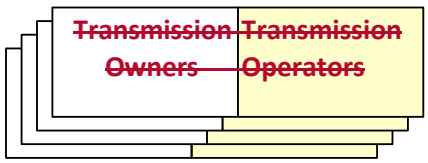
~~***Figure 1 – Transmission Operator bundled with Reliability Coordinator***~~

~~**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.~~

~~**RTO**~~

~~**Reliability Coordinator**~~

~~***Members***~~



~~***Figure 2 – Transmission Operator bundled with Transmission Owner***~~

Part 7 - Interchange Coordinator

The e-tagging process exists for scheduling Transmission usage by entities who have contracted for Transmission access. NAESB maintains the e-tagging specification. The Interchange Coordinator is equivalent to the tag authority described in the specification. (NAESB states this service has been assigned to the Sink Balancing Authority. The functional model envisions that the Sink Balancing Authority may serve as its own Interchange Coordinator or have this service provided by a separate organization.)

The "authority service"[4] is the focal point for all interactions with an e-Tag and maintains the single authoritative "copy of record" for each e-Tag received. Every Sink Balancing Authority is responsible for registering the URL of an "authority service." The authority service forwards all valid received RFI to each entity identified in the transaction as having "approval" or "viewing" rights over that RFI, and collects approvals/denials issued by these approval services. Based on time and the message(s) received from the approval services, the authority service arbitrates and sends the final disposition of the request to each entity in the distribution list. The authority service also provides the capability for both the agent (requestors of service) and approval services to interrogate the current approval state of any transaction RFI on demand.

~~The Interchange Coordinator 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.~~

~~The Interchange Coordinator provides the Balancing Authority with the individual bilateral Arranged Interchange. The Balancing Authority must track the individual Interchange Schedules in case one or more of them are curtailed by the Reliability Coordinator or by the Balancing Authority in those cases where a generator or load is interrupted. The Balancing Authority then creates a "net" interchange total for use in its energy management system as well as a "net" interchange for each neighboring Balancing Authority. The net Interchange Schedule for each neighboring Balancing Authority is used by the Receiving Balancing Authority for checkout with the neighboring Balancing Authorities.~~

~~All bilateral Interchange Transactions *that cross a Balancing Authority Area boundary* are coordinated through the Interchange Coordinator.~~

~~While the approval/denial process may utilize tools (such as computer software and communication protocols), the Model envisages that the Interchange function will be assigned to an actual organization. A Balancing Authority may serve as its own Interchange Coordinator or have this service provided by a separate organization.~~

~~**Assessing ramping capability and connectivity**. The Balancing Authority approves/denies the capability to ramp the Arranged Interchange in or out and notifies the Interchange Coordinator. The connectivity of adjacent Balancing Authorities is also verified by the Balancing Authorities before responding to the~~

[4] Definitions from NAESB:
e-Tag Agent Service: Software component used to generate and submit new e-Tags, corrections, and profile changes to an e-Tag Authority Service and to receive state information for these requests.
e-Tag Authority Service: Software component that receives e-Tag Agent Service and e-Tag Approval Service requests and responses and forwards to the appropriate approval service. Also maintains master copy of e-Tag (all associated requests), the composite state of the e-Tag, etc. and responds to queries regarding the e-Tags in its possession.
e-Tag Approval Service: Software component used to indicate individual approval entity responses when requested by the e-Tag Authority Service, as well as submit profile changes.

~~Interchange Coordinator.~~

~~**Ensuring balanced, valid Interchange Transactions**. The Interchange Coordinator 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 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 does not authorize the Transaction to become Confirmed Interchange.~~

~~**Curtailments**. The Interchange Coordinator coordinates curtailments of Confirmed Interchange ordered by the Reliability Coordinator by notifying the Balancing Authorities, Transmission Service Providers, and Purchasing-Selling Entities. The Interchange Coordinators also communicates and coordinates the resulting modified Arranged Interchange that result from the curtailments.~~

Part 8 - Transmission Service Provider

The Transmission Service Provider authorizes the use of the transmission system under its authority. In ~~most~~ some 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 ~~c~~Customer (Purchasing-Selling Entity, Generator Owner, Load-Serving Entity) with the ~~t~~Transmission information supplied by the Interchange Coordinator. The Transmission Service Provider also ensures that there is a contiguous ~~t~~Transmission path and that adjacent Transmission Service Providers~~SPs~~ are on the ~~s~~Scheduling ~~p~~Path. The Transmission Service Provider then provides its approval or denial to the Interchange Coordinator.

Providing Transmission and Ancillary Service. As its name implies, the Transmission Service Provider provides transmission service and Ancillary Service to transmission 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 transmission service according to the Transmission Owner's tariff, and within the operating reliability limits determined by the Reliability Coordinator. The Transmission Service Provider ensures necessary Ancillary Services are provided to the Transmission Operator and Balancing Authority. The Transmission Service Provider does not itself have a role in maintaining system reliability in ~~r~~Real time — that is done by the Reliability Coordinator and Transmission Operator and Balancing Authority.

The Transmission Service Provider arranges for transmission loss compensation and Ancillary Service requirements with the Balancing Authority.

Part 9 - Transmission Owner

The Transmission Owner owns its transmission 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 transmission 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 facilities or arrange for another organization (which may or may not be a Transmission Owner) to operate and/or maintain its transmission facilities.~~

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.

~~See "Transmission Operator," Section "Bundling with the Reliability Coordinator or Transmission Owner"~~

Part 10 - Distribution Provider

The Distribution Provider provides the physical connection between the end-use customers, distribution-connected energy resources, and the BES~~electric system~~, including customers served at ~~t~~Transmission level voltages. The Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. One Distribution Provider may be directly connected to another Distribution Provider, such connections must be reported to the Balancing Authority even though ~~and~~ not directly connected to the BES~~ulk Electric System~~.

The Distribution Provider maintains "local" safety and reliability and is responsible for the distribution facilities to serve end-use customers and distribution-connected energy resources. The Distribution Provider provides the switches and re-closers necessary for emergency action and information necessary for the Transmission Operator and Transmission Planner. The Distribution Provider may need to demonstrate manual ~~l~~Load-shedding capability to the Balancing Authority and Transmission Operator. Design and maintain protective relaying systems, under-frequency load-shedding systems, under-voltage Load-shedding systems, and Remedial Action Schemes that interface with the Transmission system.

~~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 functions are distinct, in many cases an organization, such as a vertically integrated utility, bundles these functions together.

~~Part 11 – Generator Operator~~

~~The Generator Owner may operate its generating facilities or designate a separate organization to perform the Generator Operation Function.~~

~~The Generator Operator operates, or directs the operation of generation facilities. The Generator Operator supports the needs of the Bulk Electric System up to the limits of the generating 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 facilities it operates, or it may be a separate organization designated by the Generator Owner to operate the 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 reliability related services through arrangements or by direction from the Transmission Operator for support of the 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.** The Generator Operator provides unit commitment schedules, generator status, and operating and availability status of generating units to the Balancing Authority.~~

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 Bulk Electric System.

Relationship with Purchasing Selling Entity. The Generator Operator receives notice of Arranged Interchange approved by the Purchasing Selling Entity.

Part 12 – Generator Owner

The Generator Owner owns its generation facilities and provides for the maintenance of those 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 facilities, or arrange for another organization to do so. In addition, the organization serving as Generator Owner may perform maintenance and facility verification, or may arrange with another organization to do so.

Part 13 – Purchase-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 transmission service with the Transmission Service Provider that provides transmission service to the LSE under a tariff or market rule.

The Purchasing-Selling Entity initiates a bilateral Interchange between Balancing Authority Areas by submitting a Request for Interchange (RFI) to the Interchange Coordinator.

Part 14 - Load-Serving Entity

The Load-Serving Entity (LSE) arranges for the provision of energy Resources and Ancillary Services to its Balancing Authority and Resource Planner in order to supply its end-use 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, o~~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 and Ancillary Services to serve the Load-Serving Entity~~'s~~ customers, or purchase capacity, ~~and~~ energy, and Ancillary Services 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~~ resource (affiliated and non-affiliated) arrangements to serve load to the Balancing Authority, which forwards this information to the Reliability Coordinator, for day-ahead analysis.

The LSE may contract for ~~reliability-related services~~ Ancillary Services through the Transmission Service Provider or the ~~M~~market ~~O~~operator (if the Load-Serving Entity 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 assets ("wires") but does take title to energy. However, while these functions are distinct, in many cases an organization, such as a vertically integrated utility, bundles these functions together.

~~The Functional Model assigns to t~~The Load-Serving Entity is responsible for the identification of loads for ~~c~~Curtailment and those critical customer loads that are to be excluded from the load-shedding systems, and the development of load profiles and load forecasts. ~~Please see Section II, 114: Roles in Load Curtailment for more detailed information.~~

The Load-Serving Entity communicates requests for ~~voluntary c~~Curtailment to the appropriate end-use customer loads~~, thereby ensuring that these loads will in fact be curtailed~~.

~~Part 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.~~

~~Part 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.~~

~~Part 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 functional entity 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.~~

~~The Market Operator is described further in Section II, Technical Discussions.~~

Part 18 - Reliability Assurer

The Reliability Assurer is subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada. The Reliability Assurer assures the reliability of the Bulk Power System in North America by developing and enforcing Reliability Standards; annually assessing seasonal and long-term reliability; monitoring the Bulk Power System through system awareness; and, educating, training, and certifying industry personnel.

~~In Version 4 of the Model, the Reliability Assurer entity and the Reliability Assurance Function replaced Version 3's Regional Reliability Organization entity and the Regional Reliability Assurance Function.~~

~~The change to Reliability Assurer reflected 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 functional entity for Reliability Assurance.~~

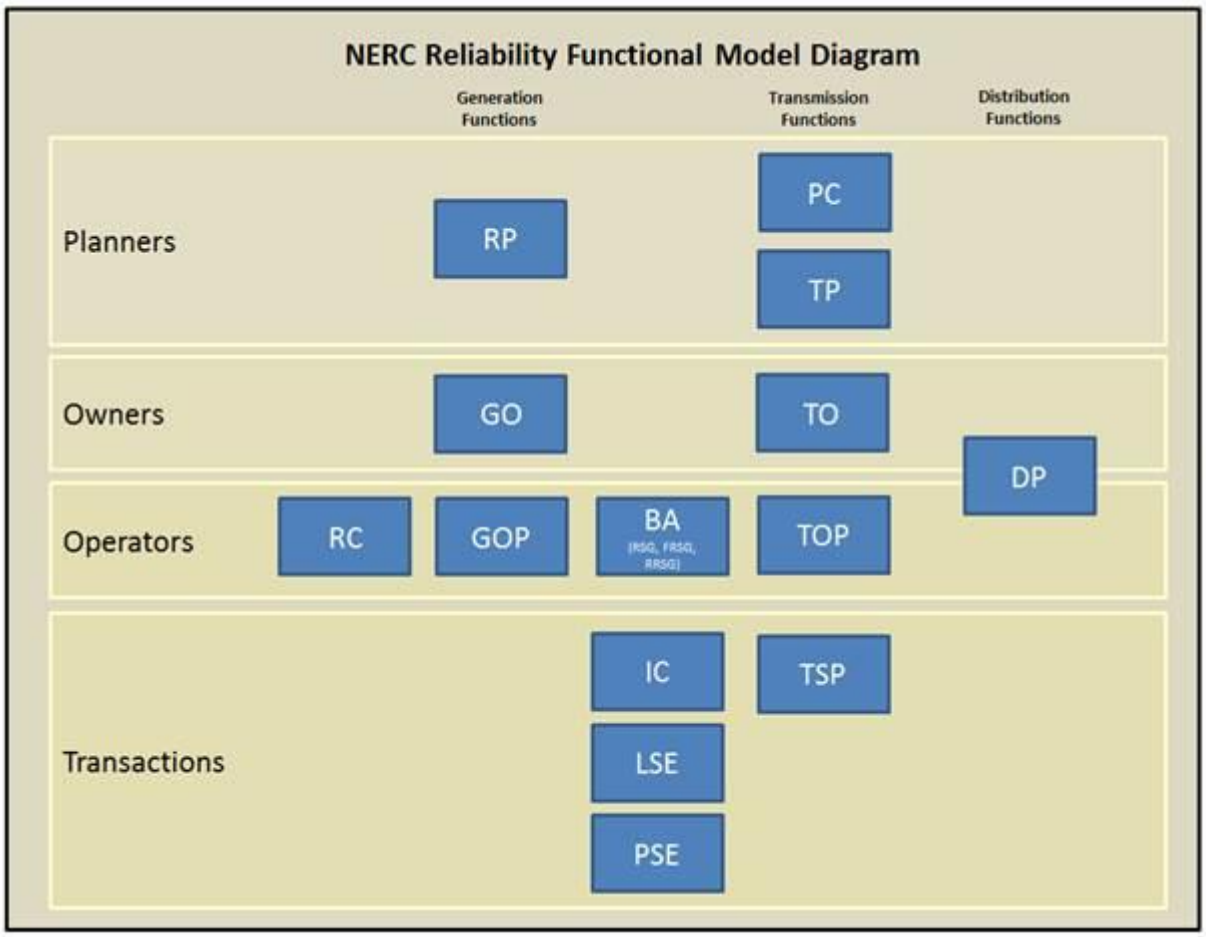
~~The role of the Reliability Assurer may be considered to provide "defense-in-depth." That is, the Reliability Assurer provides an independent assessment of Tasks performed by other functional entities, or facilitates or coordinates such Tasks. While the specific role of the Reliability Assurer is not fully developed at the present time, the following are representative of the Tasks that might be performed:~~

- ~~Perform high level evaluations, such as at a regional or 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 Interconnection level, of protection systems as they relate to the reliability of the Bulk Electric System.~~
- ~~Perform disturbance analysis evaluations.~~

~~The selection of particular Tasks for the Reliability Assurer will reflect NERC's judgment on which Tasks merit such a "defense-in-depth" approach.~~

SECTION 2 – TECHNICAL DISCUSSION

The below diagram provides an illustration of how the various functional entities can be categorized.



~~Part 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") 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. Each Function consists of a set of related reliability Tasks. The Model assigns each Function to a functional entity, that is, the entity that performs the Function's Tasks. The Model also describes the interrelationships between that functional entity and other functional entities (that perform other Functions).~~

- NERC's Standard Development Teams develop Reliability Standards that assign each reliability requirement within a standard to a functional entity, as defined in the Model.
- This is possible because a given standard requirement will be logically related to a Task within a Function. A standards requirement will be very specific whereas a Task will be more general in nature.
- NERC's compliance processes require specific organizations to register as functional entities and comply with standards requirements assigned to the functional entities.
- The Model's Functions and functional entities also provide for consistency and compatibility among different Reliability Standards.

The NERC Reliability Functional Model ("the Model") does NOT address:

- Entity Certification
- Registration
- Compliance
- Sanctions

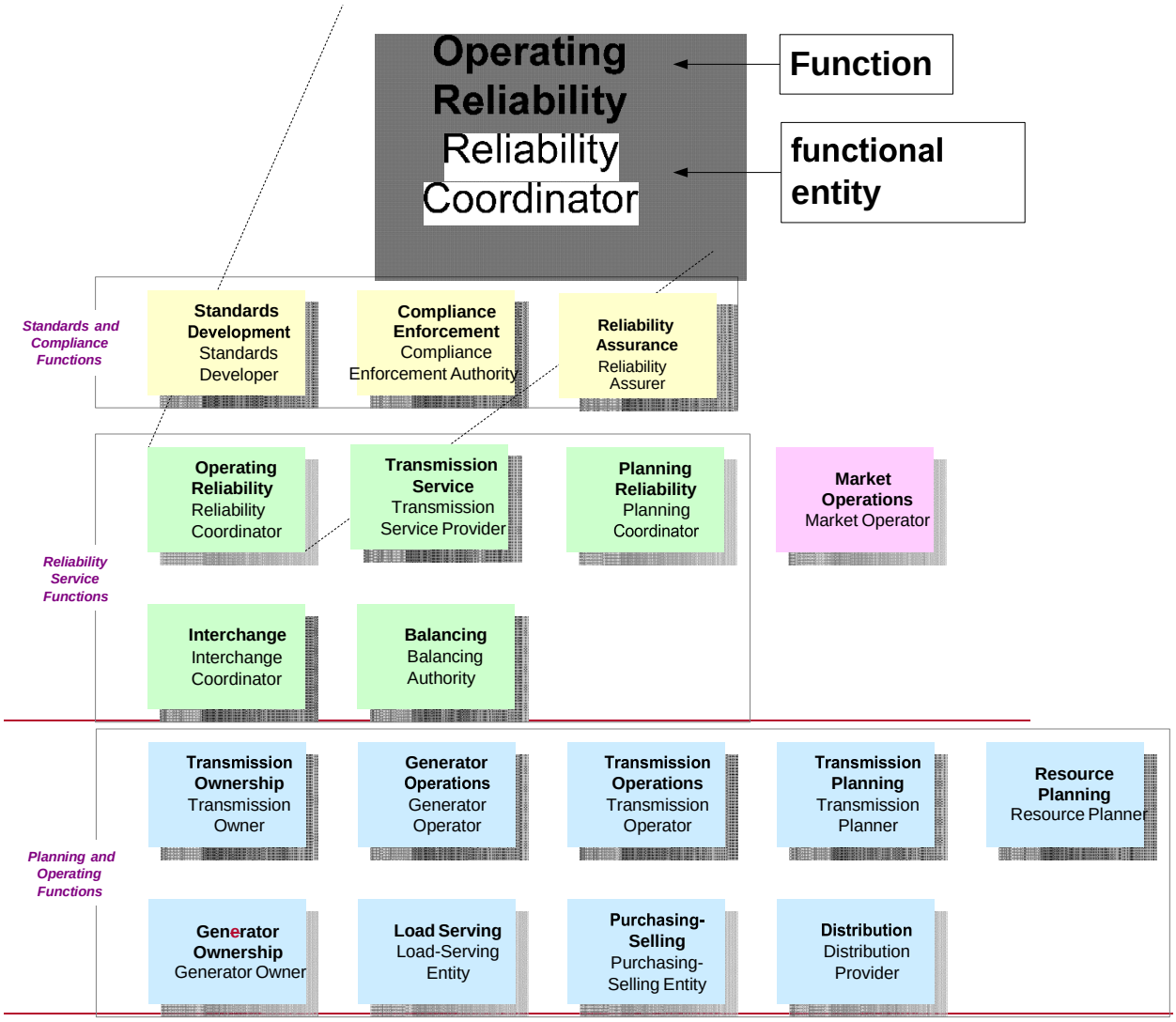
There are a number of clarifications that are important for those involved in developing standards and monitoring compliance with them. These clarifications are generally made in the Model itself, but because of their importance and potential for misinterpretation, they warrant being repeated.

The Model is a guideline, it is not prescriptive. The Model is not a standard, and does not have compliance requirements. The Model is a guideline for the development of standards and their applicability; it is not a NERC requirement. Standards developers are not required to include tasks envisioned in the model, nor are the developers precluded from developing Reliability Standards that conflict with the Model. The Reliability Standards requirements take precedence over the Model.

A Functional Entity is not an actual organization. The Model describes Tasks performed by functional entities, 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 functional entity; the Model does not reference PJM and MISO, which are specific organizations. It is through the NERC 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.

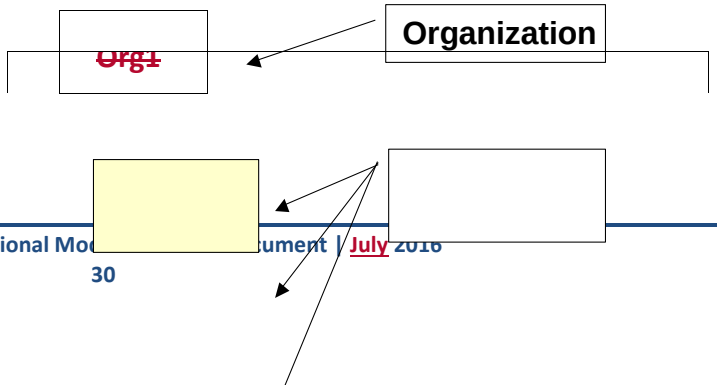
Every Function has an associated functional entity. A Function is a set of related reliability Tasks; whereas the functional entity is the name given to the category of organization that performs these Tasks. The diagram (Figure 3) of the Model includes two names within each Function box. The Function is shown in a larger typeface with the associated functional entity underneath.

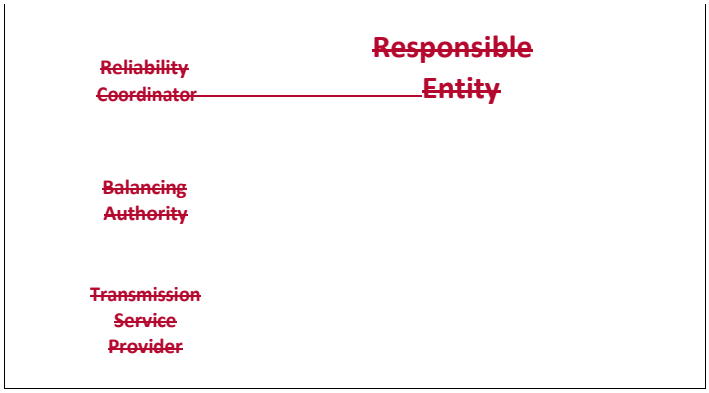


~~Figure 3 – Function and Functional Entity~~

~~Organizations, such as Regional Transmission Organizations or integrated utilities, may register with NERC as Responsible 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, and a Transmission Service Provider. In this case we say that the RTO is the **Responsible 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 Tasks within each of those Functions are performed and all applicable standards requirements met.~~




~~Reliability Coordinator~~
~~Responsible Entity~~
~~Balancing Authority~~
~~Transmission Service Provider~~

~~**Figure 4 — Organizations may "roll up" more than one functional entity.**~~

Part 2 - Reliability Standards

The Functional Model describes the Standard Development Function and the Standards Developer functional entity 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:

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 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.

1. Reliability Standards Developed Within a Regional Entity

Regional Entities may develop and propose to NERC regional reliability 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 regional reliability standard in order to implement a NERC Reliability Standard. Such a regional reliability standard, upon approval by NERC, becomes part of the NERC Reliability Standard.

Regional Entities must use a NERC-approved development process to develop these regional reliability standards. Such regional reliability standards, upon approval by NERC, become NERC Reliability Standards. As appropriate, NERC will approve the regional reliability standard as an:

- Interconnection-wide regional standard, or
- Non-Interconnection-wide regional 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.

Part 13 - Market Operations (Resource Integration)

Market OpOperations is not a reliability Ffunction. NERC does not assign standards requirements to the Market Operator. Nevertheless, Mmarket Ooperations, a commercial or market function, is included in the Functional Model, in order to provide an interface point between reliability and commercial functions.

The role of the Mmarket Ooperator[5] also varies in design and responsibilities depending on whether resources are dispatched within a full-service market or where there is not a full-service market. However, , but all Mmarket Ooperators perform a resource integration task of one form or another under a resource integration protocol set of market rules that is are recognized by a state, federal, or provincial regulator. 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. The basis and results for the resource integration algorithms are generally the same for cost-based and bid-based dispatch, which is why the Functional Model accommodates either type of protocol. Resource integration is discussed further in the following section II-4, Functional Model and Market Structures.

Multiple Balancing Authorities Within a Market Area. If the market area includes more than one Balancing Authority Area, then the market operator will also provide each Balancing Authority 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 Authority Area, and the sum of all RDISs within the market area must add to zero at each dispatch cycle.

Resource integration is discussed below for the cases of a full-service market and where there is no full-service market. Versions 4 and 5 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 for implementation. When the plan is tested for implementation, and limitations caused by transmission congestion are identified, the Balancing Authority will adjust the dispatch schedules accordingly. This constitutes a "security-constrained" dispatch.

[5] For simplicity, only the term "market operator" is used; this is intended to apply even where there is not a full-service market.

Bid-Based Resource Integration. In those areas of North America 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 Operator, in turn, provides the Balancing Authority 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. Re-dispatch 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.

Relationship between the Market Operator and Balancing Authority. In a full-service market, there is a close relationship between the ~~M~~market ~~O~~operator and the Balancing Authority. A full-service ~~M~~market ~~O~~operator performs resource integration tasks 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 ahead of ~~r~~Real-~~-~~time.

The Balancing Authority receives the plan, and implements it in real time.

2. The Market Operator Where There is not a Full-Service Market~~.~~

Cost-based Resource Integration. Where there is not a full-service market, the Market Operator will often be a traditional, vertically-integrated utility that acts also as Balancing Authority. The utility will dispatch its resources based on its incremental costs (fuel and operations and maintenance) and losses. The regulatory authority might specify the accounting rules for calculating these costs.
~~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, 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 will also be the ~~M~~market ~~O~~operator, operating on the basis of ~~n~~Net ~~i~~Interchange.

3. Summary: The Market Operator Using Different Structures

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.

~~Part 4 - The Functional Model and Market Structures~~

~~This section explains how the Functional 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 Functional 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 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. Re-dispatch 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. 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 Area, then the Market Operator will also provide each Balancing Authority 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, 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) uses this information in its economic dispatch.	Balancing Authority, 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) 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 directs the part of the utility that acts as Market Operator to develop a new dispatch plan.	Balancing Authority pulses units that are designated by the Market Operator for meeting energy and regulation service requirements. As regulating ability declines, the Balancing Authority asks the Market Operator for a new dispatch plan.

Part 25 - Providing and Deploying Ancillary and Interconnected Operations Services~~Reliability-Related Services~~

The North American electric power system is transforming to a resource mix that relies less on coal and nuclear while integrating more natural gas, wind, solar, distributed generation, and demand response resources. Additionally, the power system will change further as micro-grids, smart networks, and other advancing technologies continue to be deployed. Recognizing that these changes represent a fundamental shift in the operational characteristics of the power system with potential reliability implications, the policies that govern Ancillary Services and the characteristics of Interconnected Operations Services may evolve to address these newer resources. Proper planning and providing system operators with the ability to manage resources in real time will be required to ensure that the appropriate levels of Interconnected Operations Services are available so that reliability is maintained as the resource mix evolves.

The Building Blocks of Reliability[6]

Based on the analysis of geographic areas that are experiencing the greatest level of change in their types of resources, a number of measures and industry practices are recommended to identify trends and prepare for the transition in resource mix. These recommendations consider both real-time operations and future planning to support frequency, ramping and voltage of the system.

Frequency – The electric grid is designed to operate at a frequency of 60 hertz (Hz). Deviations from 60 Hz can have destructive effects on generators, motors, and equipment of all sizes and types. It is critical to maintain and restore frequency after a disturbance such as the loss of generation. Frequency will immediately fall given such an event. This requires an instantaneous (inertial) response from some resources and a fast response from other resources to slow the rate of fall during the arresting period, a fast increase in power output during the rebound period to stabilize the frequency, and a more prolonged contribution of additional power to compensate for lost resources and bring system frequency back to the normal level.

Ramping – Adequate ramping capability (the ability to match load and generation at all times) is necessary to maintain system frequency. Changes to the generation mix or the system operator's ability to adjust resource output can impact the ability of the operator to keep the system in balance.

Voltage – Voltage must be controlled to protect system reliability and move power where it is needed in both normal operations and following a disturbance. Voltage issues tend to be local in nature, such as in sub-areas of the Transmission and distribution systems. Reactive power is needed to keep electricity flowing and maintain necessary voltage levels.

[6] Excerpt from North American Electric Reliability Corporation (NERC) ERS Framework Report, December 2015

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):~~

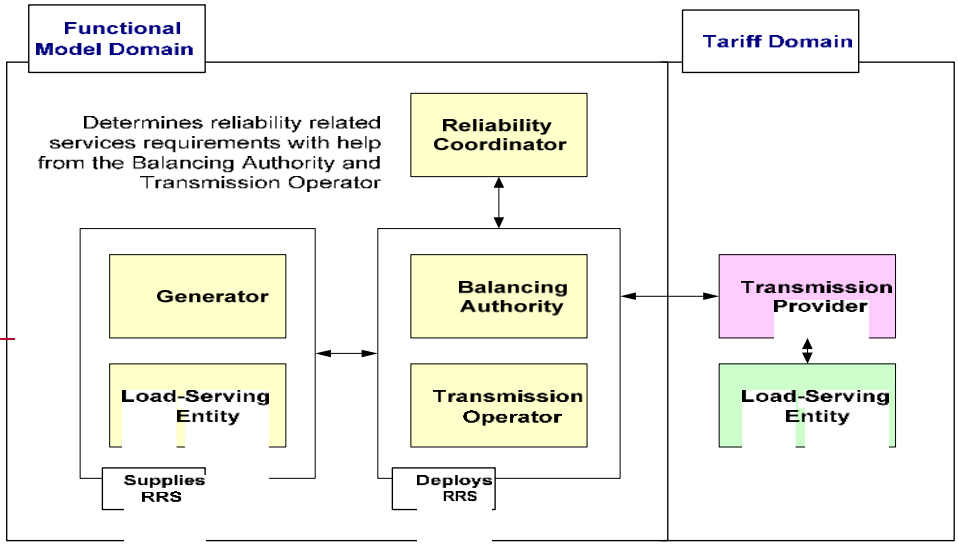


Figure 5 - Supply and Deployment of Ancillary Services and Reliability-Related Services.

The FERC pro-forma tariff requires that the Transmission Provider offer to provide Ancillary Services, as a provider of last resort, ~~the following services~~ to customers serving loads within the Transmission Provider's own area which do not purchase or self-provide:

1. Scheduling, system control, and dispatch
2. Reactive supply and voltage control from generation.
3. Energy imbalance
4. Regulation and frequency response
5. Operating reserve — spinning
6. Operating reserve — supplemental.
7. Generator Imbalance

Functional Model Domain — Interconnected Operations ~~Reliability-related~~ Services. A service (exclusive of basic energy and Transmission Services) that is required to support the Reliable Operation of interconnected Bulk Electric Systems.[7] ~~The term "reliability-related services" means those services other than the supply of energy for load that are~~ These Interconnected Operations Services 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 ~~t~~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 ~~t~~Transmission service. In addition, loads may provide reserves through load-shedding or ~~d~~Demand-~~s~~Side ~~m~~Management, and may also provide frequency response.

Ancillary Services in the “tariff domain” could be served by Interconnected Operations Services ~~reliability-related services~~ in the "reliability domain.” The Functional Model explains that the Balancing Authority, alone or

[7] Definition of Interconnected Operations Services from the NERC Glossary of Terms (as of May 15, 2016).

in coordination with the Reliability Coordinator, determines the amount required and arranges for Interconnected Operations Services ~~reliability-related services~~ to ensure balance:

- The Balancing Authority determines regulation, load following, frequency response, ramping capability and contingency reserves, ~~etc.,~~ and deploys these as Interconnected Operations Services~~reliability-related services~~.
- The Transmission Operator determines the reactive resources ~~reliability-related services~~ necessary to meet its ~~r~~Reactive ~~p~~Power requirements to maintain ~~t~~Transmission voltage within operating limits, and deploys these as its set of Interconnected Operations Services~~reliability-related services~~.
- The Reliability Coordinator, working with the Transmission Operator, determines the need for black start~~Black Start~~ capacity. The Transmission Operator cannot do this alone, because it may not have a wide enough picture of the ~~t~~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 Interconnected Operations Services ~~reliability-related services~~ depend on the ~~R~~regional and local system characteristics and regulatory requirements. The responsible organizations establish the quality and quantity of their own Interconnected Operations Services ~~reliability-related services~~, using these processes and procedures in a manner that ensures reliable operation of the BES~~compliance with the standards' requirements~~.

~~Part 6 - Managing Bilateral Interchange Transactions – Basic Concepts~~

~~Interchange that crosses multiple Balancing Authority (BA) Areas can be broken down daisy-chain fashion into individual Balancing Authority to Balancing Authority Interchange Transactions, with the Sink Balancing Authority 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 Authorities. Also, the Interchange Coordinator function "coordinates" and "communicates Interchange ("deals") that is ready for physical implementation between Balancing Authorities. The IC receives approvals that recognize ramping capability. The IC also communicates the individual Interchange information to all involved parties (Figure 6).~~

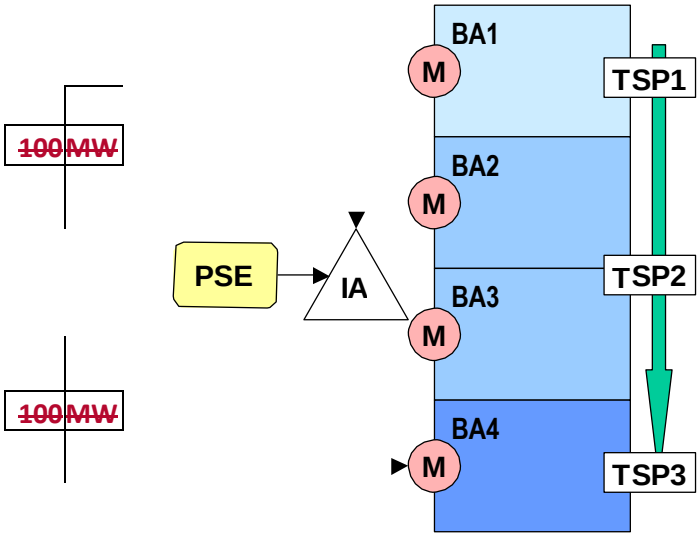


Figure 6 — The Interchange Coordinator manages transactions between the source and sink Balancing Authorities.

Managing Bilateral Interchange Transactions — Allowable Concept

The Functional Model does not prevent Balancing Authorities from scheduling Interchange with Interchange Coordinators. The ICs would ensure that the Arranged Interchange is balanced (equal and opposite) between the Source and Sink BAs. In the example in Figure 6, the IC manages a transaction from BA1 to BA4. The schedule is

BA1 → IA → BA4

and the transmission service path is

TSP1 → TSP2 → TSP3.

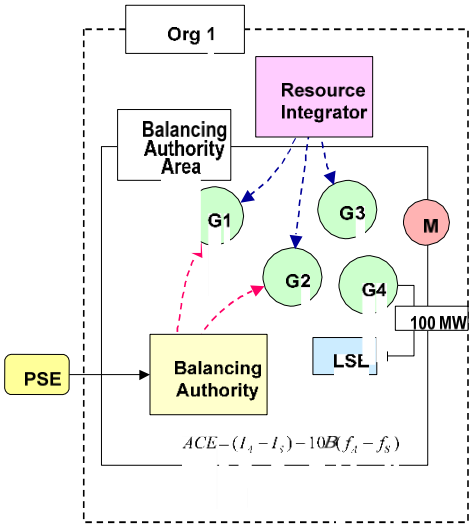


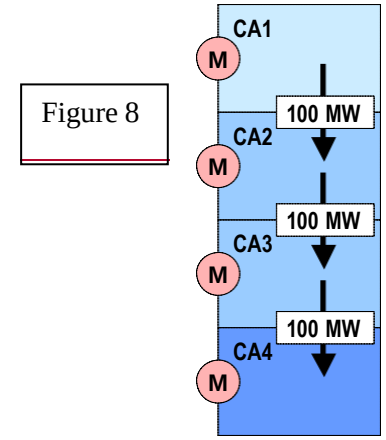
Figure 7 – The Purchasing-Selling Entity submits the bilatera transaction to the Balancing Authority for intra-BA transactions.

~~**Interchange Transactions within a Balancing Authority Area.** A bilateral Interchange within a Balancing Authority Area does not require Interchange Coordinator authorization. In the example in Figures 8 and 9, the Purchasing-Selling Entity submits the 100 MW request for Interchange to the Balancing Authority 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 Authorities 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 IC**	**Inadvertent**
BA1	+100 to BA2	+100 to IC	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 IC	0

Figure 8



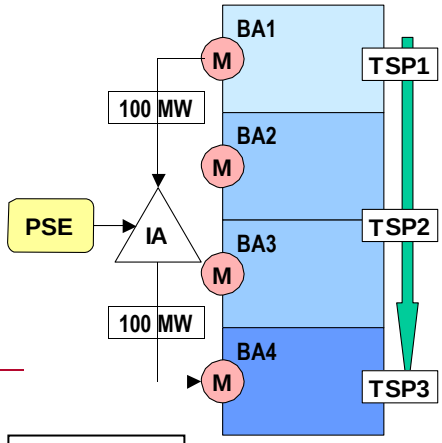


Figure 9

Part 7 - Managing Bilateral Interchange – Scheduling Agents

Some Transmission Providers provide a Scheduling Agent service for their Balancing Authority members. The Scheduling Agent provides a single point of contact for all Interchange into or out of those Balancing Authorities. For example, the Southwest Power Pool serves as a Scheduling Agent for its members, and any Balancing Authority external to SPP will schedule to any SPP Balancing Authority by way of the SPP as the Scheduling Agent. This simplifies Interchange scheduling for parties both internal and external to SPP.

In the example in Figure 10, two Interchange Coordinators arrange a total of 225 MW with the Scheduling Agent 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 Agent must ensure that the sum of the Interchange from all Interchange Coordinators is exactly equal to the sum of the Interchange from the Scheduling Agent to its Balancing Authorities:

ISA1 + ISA2 = IS1 + IS2 + IS3 + IS4

$I_{S1} + I_{S2} + I_{S3} + I_{S4} = 225$ MW

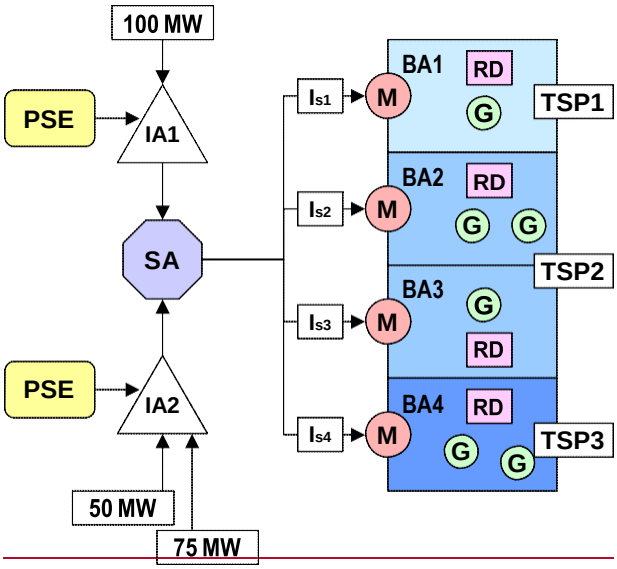


Figure 10 - The Scheduling Agent divides a 100 MW transaction among a group of Balancing Authorities.

If the Balancing Authority(ies) use a Scheduling Agent, then the Interchange Coordinator will request approvals from the Scheduling Agent — not the Balancing Authority(ies) — during the Interchange authorization process. The Interchange Coordinator will also notify the Scheduling Agent of any Interchange curtailments.

Because Interchange scheduling is an integral function of the Balancing Authority, the Functional Model Working Group defines that the Scheduling Agent is actually an agent of the Balancing Authorities. The Balancing Authorities would still be the Responsible Entities for ensuring that the Interchange from the Scheduling Agent was incorporated into the BAs' energy management systems. Some have argued that the Scheduling Agent would need to be certified and monitored to ensure that it handled the Interchange properly.

~~Part 8 – Non-coincident Resource Integrator and Balancing Authority Areas~~

~~**Bilaterals between Market Areas.** In the examples above, each Balancing Authority 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 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 within that area. In this situation, the Interchange Coordinator interfaces with the Scheduling Agent for the Market Area. Then the Scheduling Agent, working with the Market Operator will determine how the bilateral Interchange is allocated among the Balancing Authority Areas.~~

~~As was explained in the technical discussion on reliability related services, the Scheduling Agent ensures that the RDIS are properly allocated to the Balancing Authorities.~~

~~Now we can combine the Scheduling Agent's management of RDIS with bilateral Interchange Transactions as shown in Figure 11.~~

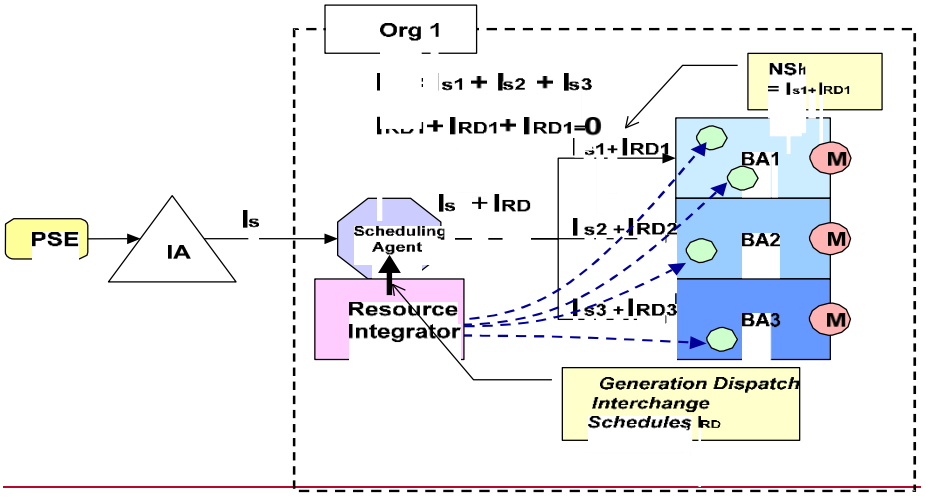
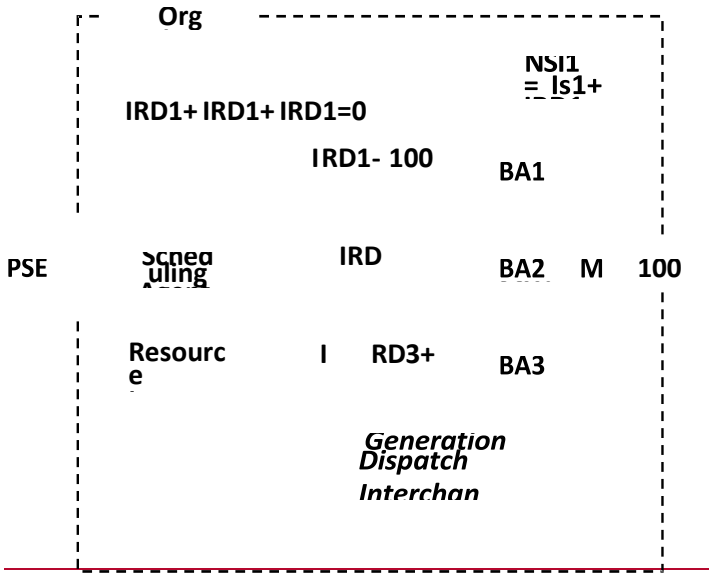


Figure 11 - The Scheduling Agent manages bilateral Interchange Transactions in to or out of the Market Area ~~as well as the Interchange Schedules that result from the~~ economic dispatch or market operations.

~~**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 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, who would then coordinate the transaction between the source and sink Balancing Authorities. The Scheduling Agent 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 Agent when the bilateral transaction is within the same Market Area.*~~

Part 39 – Implementing Interchange Coordination

Requests for Interchange (RFI) are initiated by entities (Purchasing-Selling Entities, Load-Serving Entities, or Generator Owners) who have arranged for Interchange and contracted for Transmission Service from a Transmission Service Provider. The RFIs are submitted to a (Tag) agent service who confirms all information needed and electronically sends Tags to the authority service, or the Interchange Coordinator. The Interchange Coordinator IC Ttasks are being performed by the organization functional entities registered as Balancing Authorities (BAs), specifically the Sink Balancing Authority"sink BA"[8] for a particular interchange transaction. A Sink Balancing Authority is defined as, "[the Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule."[9] It has been noted that the Functional Model could in principle have assigned the IC Tasks to the BA and avoided the need for a separate Interchange function. This approach was not followed because it was envisioned in the future that the IC Tasks could be performed by entities other than a BA, a possibility that is allowed for by defining the IC separate from the BA. Therefore, the Functional Model *accommodates* the sink BA as the IC, but does not *require* it.

The implementation of the IC 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 ICs is compatible with the approach taken in the Model:

- There is a need for a separate Interchange Coordinator functional entity
- Allowance is made for BAs to register as ICs, but organizations that are not BAs are not precluded from doing so.
- The IC is an entity, not a software tool.

The remainder of this section clarifies the context and need for an Interchange Coordinator 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 iInterchange tTransactions (Arranged Interchange) must be approved before that request is allowed to become an "iImplemented" Iinterchange transaction (or Confirmed Interchange). Without approvals, it is possible that the sum of all iInterchange sSchedules in an interconnection will not sum to zero. That, in turn, would lead to the condition that even if every Balancing Authority were controlling to zero Area Control Error, there could still be off-generation occurring because of the Net Interchange sSchedule being in error.

Historically, approvals were handled on a control area to control area basis. Net iInterchange sSchedules 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 Schedule interchange (and instead merely accepted the numbers from its individual neighbors) — what can and did happen was that individual

[8] That is, the BA in whose area the bilateral interchange transaction terminates.

[9] Definition of Sink Balancing Authority from the NERC Glossary of Terms (as of Mary 15, 2016).

schedules were active 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 Interchange Coordinator in the Functional Model recognizes a reliability concern regarding responsibility for approving a ~~r~~Request for ~~i~~Interchange, and the distribution of the information for the approved request for ~~i~~Interchange. Each and every Interchange ~~t~~Transaction that a Purchasing-Selling Entity~~SE~~ 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 Interchange ~~t~~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 Interchange ~~t~~Transactions and their respective characteristics. This step is carried out by a tagging authority, which is the Interchange Coordinator. In order to obtain approval or denial, the Interchange Coordinator sends the Request for Interchange electronically, as Arranged Interchange, to the (tag) approval service provider for the Balancing Authorities, Transmission Service Providers, Load-Serving Entities, Purchasing-Selling Entities, and Generator Owners. After obtaining approval or denial, the approval service then sends the decision to the Interchange Coordinator. If all parties approve the Interchange Transaction, the Arranged Interchange becomes Confirmed Interchange. The Interchange Coordinator then informs all parties of this status.

The other step focuses on implementing Net Interchange ~~s~~Schedules (*i.e.*, the net of the ~~t~~Transactions that were approved). This step is carried out by neighboring Balancing Authorities~~As~~. The Sink Balancing Authority is responsible for ensuring the process is properly carried out. ~~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 IC for the transaction. If a BAleft accepts a Net Schedule from BAcenter but the transactions within that Net do not agree with the complementary transactions of the accepted Net Schedule between BAcenter and BAright, then again no one can be held non-compliant if no one is registered as IC.~~

~~What is in place t~~Today ~~is~~ the NAESB ~~NERC~~ Tagging Specification is in place. ~~,~~ Under the NAESB Tagging Specification, ~~under which~~ each ~~s~~Sink Balancing Authority is responsible for providing ~~T~~ttagging ~~S~~sservices, either directly or by arranging with a third party to provide this service as its agent.[10] ~~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 (IC)".~~

~~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 Function Specification assigns the Tag Authority requirements to the entity responsible for Balancing Authority operations (*i.e.*, Sink BA).~~

[10] See, NAESB Electronic Tagging Functional Specification, version 1.8.0, approved November 7, 2007. Click here: 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 to the entity performing the Interchange function for the Sink Balancing Authority's organization (still allows the Sink BA to use third party to fulfill the tasks of the requirements).~~

Part ~~10~~ 4 - ~~Distribution Provider as Load-Serving Entity~~ Risk-Based Registration

In support of its mission to assure the reliability of the Bulk Power System, NERC has transformed its approach to compliance and enforcement to be forward-looking with a focus on high reliability risk areas. The purpose of the NERC Risk-Based Registration (RBR) initiative was to ensure that the right entities are subject to the right set of applicable Reliability Standards, using a consistent approach to risk assessment and registration. In December 2014, NERC submitted a petition for approval of proposed revisions to the NERC Rules of Procedure (ROP), seeking to implement the changes sought as a result of the RBR initiative.[11] Specifically, NERC requested major reforms to the registration process, including the elimination of the Purchasing-Selling Entity (PSE), Interchange Authority (IA), and Load-Serving Entity (LSE) functional registration categories; modifications to the thresholds for registering entities as Distribution Providers (DP); and procedural improvements to the registration process. The procedural improvements to the registration process included: (1) the establishment of a materiality test for registration, with clear procedures and criteria for evaluation of whether an entity has a material impact on reliability with respect to above-the-line and below-the-line Registry Criteria determinations; (2) an enhanced process for review by a NERC-led, multi-regional panel of certain registration, deactivation and deregistration decisions, as well as certain requests for sub-set lists of Reliability Standards; (3) development of a common registration form to facilitate uniformity in Regional Entity collection of the information from registration candidates; and (4) one-time attestations that allow entities to record that a specific Reliability Standard requirement is "Not Applicable." On March 19, 2015, the Commission issued an order largely approving proposed revisions to the NERC ROP.[12]

As outlined in the RBR petition, the ERO compliance program and stakeholders benefit from the proposed revisions as they appropriately focus resources on entities with the greater potential impact on reliability. The RBR reforms were based on the February 2011 Commission technical conference in Docket No. AD11-6-000 on *Priorities for Addressing Risks to the Reliability of the Bulk-Power System*, where there was a recognition that "if everything is a priority, then nothing is a priority."[13] Priorities must be driven by a clear understanding of risks and consequences, and the costs and benefits associated with addressing them. With a shift toward risk-based approaches and a learning industry, NERC introduced quantitative measures of reliability performance. The revisions were a result of NERC taking a risk-based approach to reliability and to incorporating lessons-learned through continuously improving and adapting operations.

Even though the three entities (PSE, IA, and LSE) were removed from the NERC Registry Criteria, these entities–as users, owners and operators of the Bulk Power System–remain within in the statutory scope of both FERC and NERC pursuant to Section 215 of the Federal Power Act. Functionally, Load-Serving Entities, Purchasing-Selling Entities and Interchange Authorities continue to exist and continue to perform in the markets or operate under open access transmission tariffs, as applicable. The revisions did not alter the NERC registered ballot body (codified in Appendix 3D of the NERC Rules of Procedure).

~~FERC Order of October 16, 2008 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 distribution provider to~~

[11] See, Petition of the North American Electric Reliability Corporation for Approval of Risk-Based Registration Initiative Rules of Procedure Revisions, Docket No. RR15-4-000 (2014).

[12] North American Electric Reliability Corporation, 150 FERC ¶ 61,213 (2015).

[13] Additional information available on FERC website: http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=5561&CalType=%20&CalendarID=116&Date=02/08/2011&View=Listview.

whose system the electric loads in retail choice areas are connected will be registered as the LSE for all loads connected to its system.[14]

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 reliability 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 distribution 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 identified 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, distribution providers provide the wires over which the load of retail power marketers is served. NERC also pointed out that, with regard to distribution 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 distribution 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 distribution 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 of the Functional Model included consideration of whether changes should be made in the Model to accommodate these changes to the Registry Criteria.

Version 5 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.

[14] This section contains extracts from the order, which may be found at http://www.nerc.com/files/Statement_Compliance_Registry_Criteria_V5-0.pdf

Part 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.[15] 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".[16]

- 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.[17]

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.

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.

[15] 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.

[16] 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.

[17] 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.

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[18]	GLOSSARY[19]	VERSION 5[20]	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	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	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-	Glossary needs to be updated
Distribution Provider	**Distribution Provider**	**Distribution Provider**	

[18] For simplicity of presentation, the definitions indicated for the Model in Version 4 are assigned to the functional entity, not the function. For example, the Model has a definition for the Standards Development function, but the definition is shown below as applying to the Standards Developer *functional entity*.

[19] Glossary version of February 12, 2008. See link at http://www.nerc.com/files/Glossary_12Feb08.pdf

[20] These definitions would replace existing definitions in the Glossary (but entities not currently defined in the Glossary would not be added).

VERSION 4	GLOSSARY	VERSION 5	COMMENT
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	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 reliability-related services) to serve the End-use Customer.~~	~~Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of~~	~~The functional entity that secures energy and transmission services (and reliability-related services) to serve the electrical demand and energy~~	~~Minor Glossary change needed.~~

VERSION 4	GLOSSARY	VERSION 5	COMMENT
	its end-use customers.	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		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	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 and operations, and coordinates activities of Responsible Entities to		The functional entity that monitors and evaluates the activities related to planning and operations, and coordinates activities of	Term not used in Reliability Standards and therefore is not required in the Glossary.

VERSION 4	GLOSSARY	VERSION 5	COMMENT
secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.		functional entities to secure the reliability of the Bulk Electric System within a Reliability Assurer Area and adjacent areas.	
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	GLOSSARY	VERSION 5	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.~~

Part 512 - ~~Reliability~~ Areas and Boundaries

~~**Assets versus Geography as the Basis for Defining Areas and Boundaries**~~

~~It is useful for organizations that are functional entities to specify an associated Area, which defines the portion of the Bulk Electric System within which their functional entity status applies. Moreover, by reviewing all of the Areas for a particular functional 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 ~~A~~areas for the functional entities that operate and plan the Bulk Electric System is electrical, namely the individual Bulk Electric System asset. That is, the building blocks are the individual ~~t~~Transmission, generation and customer equipment assets that collectively constitute the Bulk Electric System. This enables any given Bulk Electric System asset to be associated with at least one ~~single organization, with respect to any particular~~ functional 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~~ A geographic definition is not ~~adequate~~ appropriate 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 assets provides an adequate basis for defining Areas/boundaries.

The following areas and boundaries are essential for understanding how to reliably operate and plan for a particular BES asset:

1. **Reliability Coordinator Area**: The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
2. **Balancing Authority Area**: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
3. **Transmission Operator Area**: The collection of Transmission assets over which the Transmission Operator is responsible for operating.

~~1.~~4. **Transmission Planner area**: The collection of Transmission assets over which the Transmission Planner is responsible for planning.

~~2.~~5. **Planning Coordinator area**: The collection of Transmission assets over which the Planning Coordinator is responsible for coordinating planning. Its area includes one or more Transmission Planner Areas.

~~NERC Rules of Procedure specify area relationships among functional entities, 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 reliability 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 Entity for a particular Function by virtue of performing the Function's 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.~~

~~Part 13 – Generating versus Transmission Assets~~

~~The Model does not attempt to define the boundary between generating and transmission 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 facility that is determined to be a generating facility, its owner will be a Generator Owner, and its operator a Generator Operator. Correspondingly, for a facility that is determined to be a transmission 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 facility, as a result of delegating the operating of the facility to another party through an agreement, and that in all cases it is NERC's registration process, not the Model that determines assignment as a functional entity.~~

~~Part 14 – Roles in Load Curtailment~~

~~This section discusses the roles of the various functional entities that may be involved in load curtailment. These entities include: Reliability Coordinator, Balancing Authority, 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 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 end-use 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 end-use customers through the Load-Serving Entity as directed by the initiating entities, which include the Balancing Authority and the Distribution Provider, to address potential capacity/energy shortfall in the Balancing Authority area or potential overload on the Distribution Provider system.~~

~~B. Non-Voluntary Load Curtailment (Shedding)~~

~~Non-voluntary load 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 end-use 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, 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 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 and Transmission Operator, may also participate in invoking public appeals, voltage reductions, demand-side management, and even load shedding if the Balancing Authority 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

When a Balancing Authority 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 may seek voluntary load curtailment to reduce demand in its area. In this case, the Balancing Authority will communicate such a request to the Load-Serving Entity. In the event of an Energy Emergency, the Balancing Authority may direct non-voluntary load 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 and Transmission Operator.

However, the Distribution Provide 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 end-use 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 end-use customers 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 or Distribution Provider to communicate its curtailment requests to the end-use customers.~~

~~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 end-use customers, 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 Tasks. However, from a functional model viewpoint, it is the Load- Serving Entity function within that Distribution Provider organization that performs this task.~~

Part 15 – History of Revisions

Version 1

Version 1 of the Model was approved in February 2002.

Version 2

Version 2 of the Model was approved Feb. 10, 2004.[21]

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 Tasks), and Transmission Operator as the Responsible Entity for those 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, Transmission Planner and Resource Planner).

Version 3

Version 3 of the Model was approved February 13, 2007.[22] It addressed a number of issues that arose as NERC transitioned to new, mandatory and enforceable reliability 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.[23] 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 entity name was changed to Reliability Coordinator, for consistency with terminology used in reliability standards.
- Changes were made to more clearly define the Transmission Operations Tasks and the relationship of the Transmission Operator with the Reliability Coordinator
- Changes were made to the Interchange Coordinator to accommodate the practice of Balancing Authority-to-Balancing Authority interchange scheduling
- The Planning Authority 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 assets associated with the entity, that is, that area was defined electrically, not

[21] See ftp://www.nerc.com/pub/sys/all_updl/oc/fmrtg/Functional_Model_Version_2.pdf.
[22] See ftp://www.nerc.com/pub/sys/all_updl/oc/fmrtg/Function_Model_Version3_Board_Approved_13Feb07.pdf.
[23] 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.

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 functional 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 Tasks and relationships between Responsible Entities do not specify prescriptive requirements. Prescriptive requirements are specified in reliability 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 introduces the following changes:

Entity name

- Interchange Authority 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 "functional 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 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.
- 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 *functional entities*, not the *functions*, 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 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.~~

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Functional Model

~~Function Definitions and Functional Entities~~

Version 6~~5~~

Prepared by the Functional Model Advisory Group
Approved by the Standards Committee: [Month, Year]

RELIABILITY | ACCOUNTABILITY






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Section IV: Version History~~.....~~

DRAFT

Section I: Purpose of the Functional Model~~Part 1: Foreword~~

The functional model (FM) is a guideline that identifies the functions that must be performed to ensure that the Bulk Power System is planned and operated in a reliable manner. The FM describes, in general terms, the functions that must be performed to ensure reliability, the specific tasks that are necessary to perform each function, and the relationships between functional entities that perform the various tasks. In its capacity of a guideline, the FM serves to provide a framework for NERC Reliability Standards as they are developed through the standard development process. The FM is independent of any particular organizational or market structure. The focus of the FM is solely on identification of reliability-related functions and the associated tasks and relationships.

Equally important to explaining what the FM does do, is a clear explanation of what the FM does **not** do. The FM is **not** a mandatory and enforceable document. The FM is **not** a "standard" and does not have compliance effects. If there is a conflict between the FM and Reliability Standards, the Reliability Standards always take precedence. The FM is only a guideline serving to provide details on how the different functions work together to ensure the reliability of our BPS. Also, the FM is **not** intended to identify the entities responsible for NERC registration. The NERC registration process is undertaken by NERC (and the Regional Entities) pursuant to authority from FERC, ultimately derived from the Federal Power Act. The FM has no authority, ability, or intent to impact or influence the NERC Registration process. Below is an overview of the NERC Registration process, which is completely separate from, and should not be confused with, the FM guideline. Similar to conflicts with Reliability Standards, if the FM and NERC Registration do not align, NERC Registration takes precedence.

~~This document replaces version 4 of the NERC Reliability Functional Model that the NERC Standing Committees approved in September 2008.~~

~~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 function of Transmission Service Provider through tariffs or other arrangements. NERC's Operating Policies reflected this traditional electric utility industry structure, and ascribed virtually every reliability function 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 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 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 functional entities. Initially the Model dealt with operating functions, but it was subsequently expanded in Version 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.~~

Section II: Overview of the NERC Registration Process~~Part 2: Introduction~~

The NERC Registration process consists of several elements, including the NERC Registry Criteria and the NERC Compliance Registry, and involves both the Regional Entities and NERC. The process for registration is described in the NERC Rules of Procedure, Section 500 (Appendix 5A: Organization Registration and Certification Manual and Appendix 5B: Statement of Compliance Registry Criteria).

The starting point for the NERC program for monitoring and enforcing compliance with FERC-approved Reliability Standards is the process for comprehensively identifying and registering owners, operators, and users of the Bulk Power System that are responsible for performing reliability-related functions in accordance with the approved Reliability Standards.[1] The NERC Registry Criteria provides for Bulk Power System users, owners and operators that perform a function identified in Section II of the Registry Criteria, and have a material impact on Bulk Power System reliability (which is generally determined by whether they meet the threshold criteria in Section III of the Registry Criteria) to register as one or more of fifteen functions. NERC and the Regional Entities identify such entities, which are then obligated to comply with Commission-approved Reliability Standards.[2] Identified entities are registered and included on the NERC Compliance Registry.[3] The NERC Compliance Registry identifies the reliability functions that each registered entity is responsible for meeting pursuant to the requirements of Reliability Standards. Organizations listed in the NERC Compliance Registry are responsible for knowing the contents of, and complying with, Reliability Standards applicable to the reliability function(s).[4] The registration criteria for the reliability functions are specified in the NERC Statement of Compliance Registry Criteria.[5]

The potential costs and effort of registering every organization potentially within the scope of "owner, operator, and user of the BPS," while ignoring their impact upon reliability, would be disproportionate to the improvement in reliability that would reasonably be anticipated from doing so. Therefore, the two stated goals for registration are: (1) consistency between and among Regional Entities and across the continent in the application of the criteria for registering entities; and (2) registration of any entity whose facilities or operations are deemed material to the reliability of the Bulk Power System, irrespective of other considerations.[6]

~~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 that are performed to ensure the reliability of the Bulk Electric System. Each Function consists of a set of related reliability Tasks. The Model assigns each Function to~~

[1] *See*, Order on Electric Reliability Organization Risk Based Registration Initiative and Requiring Compliance Filing, Docket No. RR15-4-000, 150 ¶ 61,213 (March 15, 2015).

[2] Section 215(b)(2) of the Federal Power Act (FPA) requires all users, owners and operators of the Bulk Power System to comply with Reliability Standards approved by the Commission. Similarly, the Commission's regulations at 18 C.F.R. §39.2 and §40.2 require all users, owners, and operators of the Bulk-Power System to comply with applicable Reliability Standards and applicable rules of the ERO and Regional Entities approved by the Commission.

[3] NERC Statement of Compliance Registry Criteria (Registry Criteria) at 2 ("Organizations will be responsible to register and to comply with approved Reliability Standards to the extent that they are owners, operators, and users of the Bulk Power System, perform a function listed in the functional types identified in Section II of this document, and are material to the Reliable Operation of the interconnected Bulk Power System as defined by the criteria and notes set forth in this document.").

[4] *See*, NERC Rules of Procedure §501. The current categories of reliability functional entities are listed in Rules of Procedure Appendix 5B, Statement of Compliance Registry Criteria.

[5] *See*, NERC Rules of Procedure, Appendix 5B.

[6] *See*, NERC Rules of Procedure, Appendix 5B at 4.

a functional entity, that is, the entity that performs the function. The Model also describes the interrelationships between that functional entity 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 functional entity (that is defined in the Model and NERC's Glossary). This is possible because a given standard requirement will typically be related to a Task within a Function. A standard requirement will be very specific, whereas a 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 functional entity envisioned to ensure that all of the Tasks related to its Function are performed. The Model, while using the term "functional entity", is a guideline and cannot prescribe responsibility. It is NERC's compliance processes, backed by regulatory authority, that specify the manner in which, a functional entity is "legally responsible" for meeting the standards requirements assigned to that functional entity.

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 Group (FMWG) 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 Tasks within a Function.

Function. A set of related reliability 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).

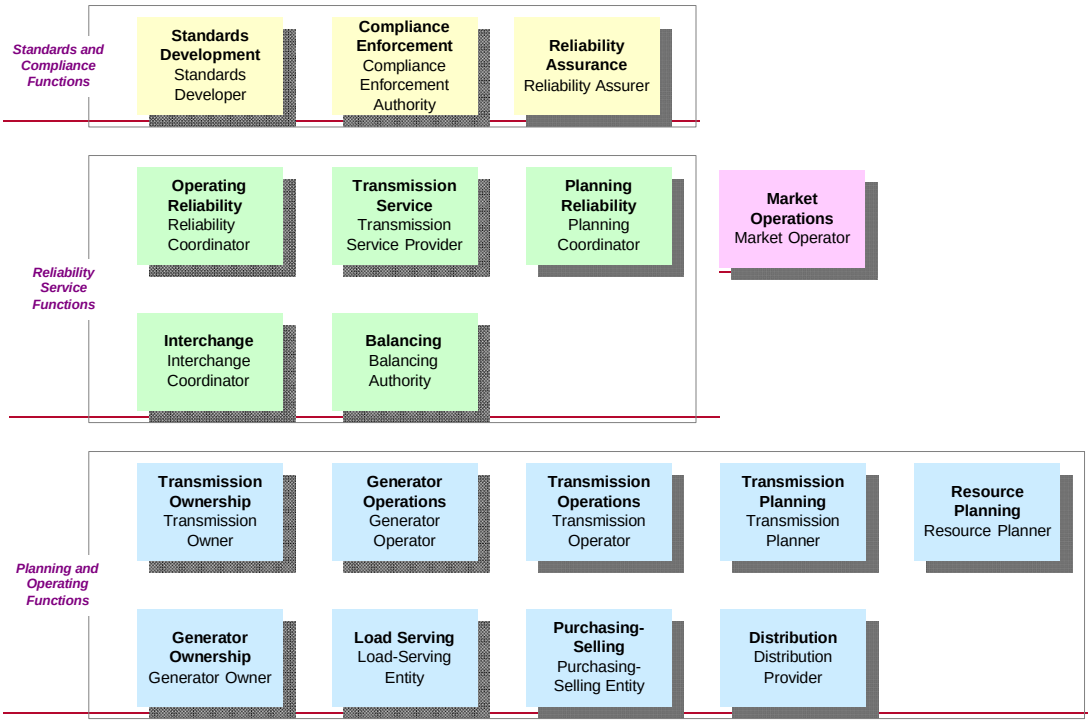
End-use Customer. The party served by a Load-Serving Entity (energy) and Distribution Provider (wire service).

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 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 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.

~~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 Coordinator~~
~~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~~

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 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 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.

0. The Model must be *complete*, that is, it must include all reliability 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 Task in the Model and therefore be assignable to a particular functional entity.

0. The Model must group these 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 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 functional entity. That is, the fundamental reliability Tasks, and hence the Function, remain the same – all that has changed is *how* the Function is performed. Examples of such groups are a reserve sharing group (a collection of entities that are Balancing Authorities), or a planned resource sharing group.

0. The Model is structured to ensure there are no gaps or overlaps in the performance of operation Tasks in the operating timeframe anywhere in the Bulk Electric System. This is achieved in part by associating an "area" of purview for each functional entity. 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.

0. Tasks describe *what* is to be done, not *how* it is to be done.

0. The Model is a guideline that describes reliability 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 functional entity, or the delegation or splitting of responsibility for meeting standards requirements.

~~Clarification Service~~

~~The Functional Model is a reference tool that links functional entities with associated reliability- related functions and respective Tasks. Drafting teams use the Functional Model to help them determine which functional entity should be required to comply with each requirement in a reliability standard.~~

~~From time to time questions of clarification and interpretation arise. The FMWG 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 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 FMWG facilitator with a request for clarification.~~

0. ~~The NERC Staff assigned as the FMWG facilitator will convene a conference call/meeting of available members of the FMWG 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 FMWG and available members of the drafting team to discuss the issues in more detail.~~
0. ~~Each FMWG 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.~~

Section III: ~~Part 3:~~ Functions and Functional Entities

This section defines the reliability-related functions and functional entities that perform the associated ~~T~~tasks that are necessary to plan and operate the Bulk Electric System in a reliable manner. This section also identifies the relationships between various functional entities that are formed in order to perform the reliability-related tasks. ~~characterizes the functional entities that perform these 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 Tasks under specific Functions to aid in the development of standards. Relationships between functional entities in the Model are reciprocal. Where~~ In some instances, a one-to-one relationship may exist~~s~~ between two functional entities; in other instances, there may be ~~, the Model will include the reciprocal relationship specifically; and where~~ a one-to-many relationship. ~~exists, the reciprocal relationships are implied.~~

~~Functional Model Diagram~~

~~Standards Development and Standards Developer~~

~~Standards Development~~

~~Tasks~~

~~0. Develop and maintain a standards development process.~~

~~0. Develop Reliability Standards for the planning and operation of the Bulk Electric System.~~

~~Standards Developer~~

~~Definition~~

~~The functional 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 Reliability Standards Development Procedure and 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.[7]~~

~~Relationships with Other Functional Entities~~

- ~~0. Receives request for Reliability Standards through the public process.~~
- ~~0. Sends Reliability Standards to the Compliance Enforcement Authority.~~

~~[7] There are also Regional Criteria that are requirements that Regions create and enforce, that are not included in the Model.~~

~~Compliance Enforcement and Compliance Enforcement Authority~~

~~Compliance Enforcement~~

~~Tasks~~

~~0. Develop, maintain and implement a compliance enforcement process.~~

~~0. Evaluate and document compliance.~~

~~Compliance Enforcement Authority~~

~~Definition~~

~~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~~

~~2. Receives Reliability Standards from the Standards Developer.~~

~~3.~~**1.** ~~Administers the compliance enforcement process for all functional entities as required by Reliability Standards.~~

Reliability Assurance and Reliability Assurer

Reliability Assurance

Tasks

1. Develop and maintain Reliability Standards that apply to Bulk Power System owners, operators, and users and that enable the Reliability Assurer 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.
2. Develop and implement a compliance 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 the Reliability Assurer has been given enforcement authority.
3. Develop and maintain a program for identifying and registering those entities that are responsible for compliance with the governmental-approved Reliability Standards.
4. Provide for certification of all entities with primary reliability responsibilities requiring certification.
5. Provide a mechanism to ensure system operators are provided the education and training necessary to obtain the essential knowledge and skills and are therefore qualified to operate the BES.
6. Provide reliability readiness evaluation and improvement, and formation of sector forums if necessary for reliability.
7. Develop a reliability assessment and performance analysis program that conducts reviews and assessments of the overall reliability of the interconnected BPS, including:
    - 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.
    - 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.
    - Review, analyze, and report on Regional Entity self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.
    - Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on Bulk Power System reliability.
    - 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.
8. Provide leadership, coordination, technical expertise, and assistance to the industry in responding to a major event.
9. Provide the education and training necessary for Bulk Power System personnel and regulators to obtain the essential knowledge necessary to understand and operate the BES.
10. Through the use of appropriate functional entities 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.

11. 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.

~~1. Coordinate reliability assurance among adjacent Reliability Assurers through the development of necessary protocols and processes.~~

~~1. Coordinate the activities related to maintaining critical infrastructure protection.~~

~~1. 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.~~

~~1. Identify and address gaps in reliability processes and responsibilities.~~

Reliability Assurer

Definition

Subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada, assure the reliability of the Bulk Power System in North America by developing and enforcing Reliability Standards; annually assessing seasonal and long-term reliability; monitoring the Bulk Power System through system awareness; and, educating, training, and certifying industry personnel. ~~The functional 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. Develop Reliability Standards that identify the functional entities responsible for complying with the Reliability Standard, including: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, Planning Coordinators, Transmission Planners, Resource Planners, and Distribution Providers.

2. Obtain the information necessary to monitor compliance with Reliability Standards from functional entities, including: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, Planning Coordinators, Transmission Planners, Resource Planners, and Distribution Providers.

3. Obtain the information necessary to complete registration from the appropriate functional entities, including: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, Planning Coordinators, Transmission Planners, Resource Planners, and Distribution Providers.

~~0. Coordinates reliability assurance activities of the functional entities within the Reliability Assurer area.~~

~~0. Coordinates reliability assurance activities with adjacent Reliability Assurers.~~

~~0. Coordinates critical infrastructure protection programs with functional entities.~~

~~0. Collects information from functional entities related to Reliability Assurance processes.~~

Planning Reliability and Planning Coordinator

Planning Reliability

Tasks

1. Establish data requirements necessary to develop power system models for analysis within the Planning Coordinator area. ~~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. Collect and validate information from Transmission Planners, such as modeling data, to perform a Transmission assessment of the Planning Coordinator area. ~~Define information required for planning purposes, and facilitate the process for consolidating and collecting or developing such information, including:~~

   - ~~Transmission facility characteristics and ratings.~~
   - ~~Demand and energy forecasts, capacity resources, and demand response programs.~~
   - ~~Generator unit performance characteristics and capabilities.~~
   - ~~Long-term capacity purchases and sales.~~

~~7.~~3. Assess the performance of the Transmission system, with the loads, resources, and proposed projects included in the Transmission Planner's Planning Assessment (including any Corrective Action Plan(s)). ~~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.~~

   - ~~Evaluate the plans that are in response to long-term (generally one year and beyond) customer requests for transmission service.~~
   - ~~Review transmission facility plans required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.~~
   - ~~Review and determine transfer capability (generally one year and beyond) as appropriate.~~
   - ~~Monitor and evaluate transmission expansion plan and resource plan implementation.~~
   - ~~Coordinate projects requiring transmission outages that can impact reliability and firm transactions.~~

~~13.~~4. Coordinate with adjoining Planning Coordinators to develop interconnection models with appropriate loads, resources, and System topology. ~~so that system models and resource and transmission expansion plans take into account modifications made to adjacent Planning Coordinator areas.~~

5. Evaluate and report on the performance of the consolidated Transmission assessments. ~~Develop and maintain transmission and resource (demand and capacity) system models to evaluate transmission system performance and resource adequacy.~~

~~14.~~6. Evaluate interconnection reliability concerns among affected Planning Coordinators.

Planning Coordinator

Definition

The ~~functional~~ responsible entity that coordinates ~~, facilitates,~~ and integrates ~~and evaluates (generally one year and beyond)~~ transmission ~~f~~Facilit~~ies~~y and service plans, ~~and~~ resource plans, and Protection Systems.[8] ~~within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.~~

Introduction to the Planning Coordinator

By its very nature, BES planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the other systems. The Planning Coordinator is responsible for coordinating the assessment~~ing~~ of the BES within its ~~the longer-term reliability of its~~ Planning Coordinator area. The PC assessment includes the collection of Transmission assets over which the Planning Coordinator is responsible for coordinating planning ("PC Area"). The PC Area is normally comprised of more than one Transmission Planner; however, ~~While~~ the area under the purview of a Planning Coordinator may include as few as one Transmission Planner~~, and one Resource Planner,~~ ~~t~~The Planning Coordinator's scope of activities is intended to span a broader area that may include BES assets of multiple Transmission Planners. All BES Facilities should be assigned to a Transmission Planner and to a Planning Coordinator, so that there are no gaps in the assessment of the BES. ~~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 system does can affect the other systems.~~ Planning Coordinators work through a variety of processes ~~mechanisms~~ to conduct facilitated, coordinated, joint, centralized, or regional planning activities to the extent that all portions of the interconnected BES ~~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. Establish ~~Coordinates~~ power system modeling data requirements in conjunction with interconnected ~~and collects data for system modeling from~~ Transmission Planners ~~Resource Planner,~~ and other Planning Coordinators.
2. Collect data for power system modeling and assessments from the Transmission Planner.
~~2.~~3. Determine ~~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.~~4. Exchange information on ~~Coordinates~~ Contingencies, criteria, System Operating Limits (SOLs), Remedial Action Schemes (RAS), automatic load-shedding schemes, and plans with the Reliability Coordinator and other Planning Coordinators ~~on reliability issues~~.
~~4.~~5. Assess the performance of the Transmission system, in coordination with Transmission Planners~~Receives plans from Transmission Planners and Resource Planners~~.
~~5. Collects information including:~~
   - ~~Transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.~~
   - ~~Demand and energy forecasts, capacity resources, and demand response programs from~~

[8] Definition of Planning Authority from the NERC Glossary of Terms (as of May 15, 2016). In the Glossary, Planning Coordinator and Planning Authority are defined interchangeably.

~~Load-Serving Entities, and Resource Planners.~~

~~. Generator unit performance characteristics and capabilities from Generator Owners.~~

~~. Long-term capacity purchases and sales from Transmission Service Providers.~~

~~10.~~6. Collect~~s~~ and review~~s~~ reports on ~~t~~Transmission, loads and resource~~s plan implementation~~ from ~~Resource Planners and~~ Transmission Planners.

~~11. 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.~~

~~12. Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system.~~

~~13.~~7. Facilitate~~s~~ the integration of the respective plans of the ~~Resource Planners and~~ Transmission Planners within the Planning Coordinator area, and adjacent Planning Coordinator areas, as appropriate.

a. Review~~s~~ 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, facilitate~~s~~ the development of alternative solutions for plans that do not meet those reliability performance criteria ~~needs~~.

Transmission Planning and Transmission Planner

Transmission Planning

Tasks

1. Develop and ~~M~~maintain ~~and develop, in cooperation with adjacent and overlapping Transmission Planners,~~ methodologies, criteria and tools for the analysis and simulation of the ~~t~~Transmission systems ~~in the evaluation and development of transmission expansion plans related to resource adequacy plans~~.

2. ~~Define, consolidate and collect or d~~Develop, acquire and validate~~, in cooperation with adjacent and overlapping Transmission Planners,~~ information required for Transmission assessments~~planning purposes~~ including:

    a. Transmission ~~f~~Facility characteristics and ~~r~~Ratings.

    b. Demand and Electrical ~~e~~Energy forecasts, capacity resources, and Demand-Side Management (DSM) ~~demand response~~ programs.

    c. Generator unit performance characteristics and capabilities.

    d. Commitments for firm Transmission Interchange.~~Long-term capacity purchases and sales~~

    e. Load forecasts and generation dispatch scenarios.

3. Develop and ~~M~~maintain ~~transmission~~ power system models (steady state, dynamics, and short circuit) necessary for the assessment of Transmission system ~~to evaluate Bulk Electric System~~ performance for identified scenarios.

4. Exchange information with other ~~Coordinate with adjacent and overlapping~~ Transmission Planners and the Planning Coordinator to achieve an interconnected ~~so that system~~ model~~s and resource and 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 the performance of the Transmission system with the anticipated topology and scenarios of loads and resources ~~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~~.

    ~~. Evaluate the plans that are in response to long-term (generally one year and beyond) customer requests for transmission service.~~

    ~~. Evaluate and plan for all requests required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.~~

    ~~. Determine transfer capability values (generally one year and beyond) as appropriate.~~

    ~~. Monitor, evaluate and report on transmission expansion plan and resource~~

~~plan implementation.~~

- ~~Coordinate projects requiring transmission outages that can impact reliability and firm transactions.~~

~~5. Notify Generation Owners, Resource Planners, Transmission Planners and Transmission Owners of any planned transmission changes that may impact their facilities.~~

~~5. Define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability needs.~~

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.[9]

Introduction to the Transmission Planner

The Transmission Planner is responsible for assessing the long~~er~~ term (generally one year and beyond) Transmission system performance within ~~reliability of~~ its Transmission Planner area. The TP assessment includes the collection of Transmission assets over which the Transmission Planner is responsible for planning ("TP Area"). By its very nature, BES~~ulk Electric System~~ planning involves multiple entities. Since all electric ~~s~~Systems within an integrated network are electrically connected, changes planned in ~~whatever~~ one part of the ~~s~~System ~~does~~ can affect the other parts of the ~~s~~System~~s~~. 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.~~ All BES Facilities should be under the purview of at least one Transmission Planner.

Relationships with Other Functional Entities

1. Coordinate~~s~~ and collect~~s~~ data (steady state, dynamics, and short circuit) for power system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, Resource Planners~~, other Transmission Planners,~~ Transmission Owners, ~~and~~ Transmission Service Providers, and other Transmission Planners.
2. Collect~~s~~ 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. Commitments for firm Transmission Interchange ~~Long-term transmission capacity purchases and sales~~ from Transmission Service Providers.
3. Inform~~s~~ 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.~~4. Coordinate~~s~~ ~~the evaluation of~~ BES~~ulk Electric System~~ expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.

~~6.~~5. Report~~s~~ on and coordinate~~s~~ its BES~~ulk Electric System~~ expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service

[9] Definition of Transmission Planner from the NERC Glossary of Terms (as of May 15, 2016).

Providers, Transmission Owners, Transmission Operators and Reliability Assurers.

~~7.~~6. Notify~~ies~~ other Transmission Planners, Transmission Owners, Transmission Operators and other entities that may be impacted by~~of~~ any planned BES~~ulk Electric System~~ changes.

~~8.~~7. Coordinate~~s~~ with Distribution Providers, Transmission Owners, Generator Owners and Load-Serving Entities in the evaluation and plans for all requests required to integrate new (~~E~~end-use ~~C~~customer, generation, and ~~t~~Transmission) ~~f~~Facilities into the BES~~ulk Electric System~~.

~~9.~~8. Submit~~s~~ and coordinate~~s~~ the plans for the interconnection of ~~f~~Facilities to the BES~~ulk Electric System~~ within its Transmission Planner area with other Transmission Planners and the Planning Coordinator~~Resource Planners~~, as appropriate.

~~10.~~9. Coordinate~~s~~ and develop~~s~~ ~~t~~Transfer ~~c~~Capability values with other Transmission Planners, Reliability Coordinators, Transmission Operators, Transmission Owners, ~~and~~ Transmission Service Providers, and the Planning Coordinator.

~~11.~~10. Coordinate~~s~~ with Transmission Owners and Generator Owners to define system protection and control needs and requirements, including ~~special protection systems (r~~Remedial ~~a~~Action ~~s~~Schemes~~),~~ to meet reliability needs.

11. Receive~~s~~ maintenance schedules and construction plans from Transmission Operator or Transmission Owner for input into and evaluation of BES~~ulk Electric System~~ expansion plans.

Resource Planning and Resource Planner

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.~~1. ~~Develop and maintain resource (demand and capacity) models~~ Acquire or develop the tools needed to evaluate long-term resource ~~a~~Adequacy for a specific set of loads.

~~4.~~2. ~~Collect~~ Acquire or develop the data and information required for performing periodic resource ~~a~~Adequacy ~~purposes~~assessments.~~, including:~~

- ~~demand and energy forecasts, capacity resources, and demand response programs,~~
- ~~generator unit performance characteristics and capabilities, and~~
- ~~long-term capacity purchases and sales and~~
- ~~transmission (interface) limits.~~

3. Determine the reliability criteria used as the basis for assessing long-term resource Adequacy.

~~9.~~4. Perform periodic resource Adequacy assessments and document the results.

5. Evaluate future ~~, develop, document, and report on a~~ resource alternatives~~. adequacy plan for its portion of the Transmission Planner and Planning Coordinator area~~.

~~10.~~6. Create and periodically update a long-term resource plan~~Assist in the evaluation of the deliverability of resources~~.

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 Planning Authority ~~Resource Planner~~ area.[10]

Relationships with Other Functional Entities

1. Collect data and information required for performing periodic resource Adequacy assessments from one or more of the following entities as necessary: Load-Serving Entity, Generator Owner, Generator Operator, Transmission Planner, Planning Coordinator, and Transmission Service Provider.

~~1.~~2. Provide long-term ~~Coordinates the~~ resource plan information ~~models with~~ to the ~~its~~ Transmission Planner for power system modeling and Planning Assessments~~Planning Coordinator~~.

~~2.~~3. Receive information from~~Coordinates with~~ the ~~Transmission Owners and~~ Transmission Planners regarding submitted resource plan ~~on the~~ deliverability ~~of resources to customers~~.

~~3.~~4. Provide resource plan recommendations to the affiliated ~~Coordinates with and collects data for resource planning from the Load-Serving Entities,~~ Generator Owner and Load-Serving Entity~~s, Generator Operators, Transmission Planners, Transmission Operators, Interchange Coordinators, and Reliability Assurers~~.

~~4.~~5. Coordinate~~s~~ with Transmission Planners~~,~~ and 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.~~6. Assess alternative ~~Works~~ plans with ~~the Planning Coordinator and~~ Transmission Planners to identify potential alternative ~~transmission~~ solutions to meet ~~Resource Planner~~resource Adequacy ~~plans~~requirements.

~~8. Applies methodologies and tools for the analysis and development of resource adequacy plans from the Planning Coordinator.~~

[10] Definition of Resource Planner from the NERC Glossary of Terms (as of May 15, 2016).

Reliability Operations and Reliability Coordinator

Reliability Operations

Tasks

1. Monitor all reliability-related parameters within the reliability area, including generation dispatch and ~~generation/transmission~~ maintenance plans for generation and Transmission.
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 Interconnected Operations Services (IOS) ~~reliability-related services~~ requirements for:
    a. balancing generation and load,[11] and
    b. ~~transmission~~ reliability of Transmission ~~(*e.g.*, reactive requirements, location of operating reserves).~~
5. Perform reliability analysis (actual and ~~c~~Contingency) for the reliability area.
6. Direct revisions to ~~t~~Transmission maintenance plans as permitted by ~~a~~Agreements.
7. Direct revisions to generation maintenance plans as permitted by ~~a~~Agreements.
8. Direct implementation of emergency[12] procedures including load-shedding.
9. Direct and coordinate restoration of the BES for its RC Area~~system restoration~~.
10. Curtail Confirmed Interchange that adversely impacts reliability.
11. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.

~~11.~~12. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

[11] The Glossary definition of "Load" is not appropriate because the Glossary definition refers to end-use customer or end-use device; the Glossary definition does not incorporate the concept of quantity.
[12] The Glossary definition of "Emergency" is not appropriate because the definition is limited in application to the BES. In this context, the RC may encounter an emergency situation that is broader than the circumstances described in the Glossary definition.

Reliability Coordinator

Definition

~~The functional entity that maintains the Real-time operating reliability of the Bulk Electric 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.[13]

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~~Wide-~~a~~Area view. Wide-Area view means the entire Reliability Coordinator area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.[14] The ~~w~~Wide-~~a~~Area view includes situational awareness of its neighboring Reliability Coordinator Areas. ~~Its scope includes both transmission and balancing operations~~The RC ~~, and it~~ has the authority to direct other functional entities to take certain actions to ensure that its Reliability Coordinator Area operates reliably. Its scope includes both:

1. **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 Transmission Operator Area~~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~~Wide-~~a~~Area~~"~~ 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~~Wide-~~a~~Area~~"~~ 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.

2. **Balancing operations**. The Reliability Coordinator ensures that the generation-~~d~~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-~~d~~Demand-~~i~~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. Coordinate~~s~~ with other Reliability Coordinators, Transmission Planners, and Transmission

[13] Definition of Reliability Coordinator from the NERC Glossary of Terms (as of May 15, 2016).
[14] Definition of "Wide-area" from the NERC Glossary of Terms (as of May 15, 2016).

Service Providers on ~~t~~Transmission system[15] limitations.

2. Receive~~s~~ facility[16] and operational data from Generator Operators, Distribution Providers, Load-Serving Entities, Transmission Owners, Generator Owners, and Transmission Operators.
3. Receive~~s~~ generation dispatch from Balancing Authorities and issue~~s~~ dispatch adjustments to Balancing Authorities to prevent exceeding limits within the Reliability Coordinator Area (if not resolved through market mechanisms).
4. Receive~~s~~ integrated operational plans from Balancing Authorities for reliability analysis of Reliability Coordinator Area.
5. Receive~~s~~ ~~t~~Transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis.
6. ~~Develops~~Provide Interconnection Reliability Operating Limits (IROLs)~~, based on Transmission Owners' and Generator Owners' specified equipment ratings,~~ ~~and provides them~~ to those functional entities with a reliability-related need~~Transmission Operators~~.
7. Assist~~s~~ Transmission Operators in calculating and coordinating System Operating Limits.
8. Provide~~s~~ reliability analyses to Transmission Operators, Generator Operators and Balancing Authorities in its area as well as other Reliability Coordinators.
9. Direct~~s~~ Generator Owners and Transmission Owners to revise generation and ~~t~~Transmission maintenance plans that are adverse to reliability.
10. Receive~~s~~ balancing information from Balancing Authorities for monitoring.
11. Receive~~s~~ final approval or denial of Arranged Interchange from Interchange Coordinator.

~~12. Provide IROLs and TTC to the Transmission Service Provider for ATC calculation.~~

~~13.~~12. Develops operating agreements or procedures with Transmission Owners.

~~14.~~13. Coordinate~~s~~ with Transmission Operators on ~~system~~ restoration plans, contingency[17] plans and Interconnected Operations Services (IOS)~~reliability-related services~~.

Real-time

~~15.~~14. Coordinate~~s~~ reliability processes and actions with and among other Reliability Coordinators.

~~16.~~15. Receive~~s~~ Real-time operational information from Balancing Authorities, Interchange Coordinators and Transmission Operators for monitoring.

~~17.~~16. Issue~~s~~ reliability alerts to Generator Operators, Transmission Operators, Transmission Service Providers, Balancing Authorities, Interchange Coordinators, Regional Entities and NERC.

~~18.~~17. Issue~~s~~ corrective actions and ~~e~~Emergency procedure~~s~~ directives ~~(*e.g.*, curtailments or load shedding)~~ to Transmission Operators, Balancing Authorities, Generator Operators, Distribution Providers, and Interchange Coordinators.

[15] The Glossary definition of "System" is not appropriate in this context because the limitations may not always include a combination of generation, transmission, *and* distribution.

[16] The Glossary definition of "Facility" is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application to include non-BES elements (*e.g.*, industrial equipment).

[17] The Glossary definition of "Contingency" is not appropriate because application in this context is not limited to power system contingency (*i.e.*, N-1 event); in this context, intended to have broader meaning.

~~19.~~18. Specify~~ies~~ reliability–related requirements to Balancing Authorities.

~~20.~~19. Receive~~s~~ verification of ~~e~~Emergency procedures from Balancing Authorities.

~~21.~~20. Receive~~s~~ notification of Confirmed Interchange changes from Balancing Authorities.

~~22.~~21. Order~~s~~ re-dispatch of generation by Balancing Authorities.

~~23.~~22. Direct~~s~~ use of flow control devices by Transmission Operators.

~~24.~~23. Respond~~s~~ to requests from Transmission Operators to assist in mitigating equipment overloads.

Balancing and Balancing Authority

Balancing

Tasks

1. Control any of the following combinations within a Balancing Authority Area:
    a. ~~Load and generation (an isolated system)~~Demand and resource
    b. ~~Load~~ Demand and Confirmed Interchange
    c. Generation and Confirmed Interchange
    d. Generation, ~~load~~Demand, and Confirmed Interchange
2. Calculate ~~a~~Area ~~c~~Control ~~e~~Error (ACE) within the reliability area.
3. Operate in the Balancing Authority Area to maintain Demand and resource~~load-interchange-generation~~ balance.
4. Review generation commitments, dispatch, and ~~load~~ Demand forecasts.
5. Formulate an operational plan (*e.g.,* generation commitment, outages~~, etc.~~) for reliability evaluation.
6. Approve Arranged Interchange from ~~r~~Ramping ability perspective.
7. Implement Confirmed Arranged Interchange.
8. Operate the Balancing Authority Area to contribute to Interconnection frequency.
9. Monitor and report control performance and disturbance[18] recovery.
10. Provide balancing and energy accounting (including hourly checkout of Confirmed Arranged Interchange, Implemented Interchange and actual ~~i~~Interchange), and administer inadvertent energy paybacks.
11. Determine needs for Interconnected Operations Services~~reliability-related services~~.
12. Deploy Interconnected Operations Services (IOS)~~reliability-related services~~.
13. Implement ~~e~~Emergency procedures.
14. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
~~14.~~15. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

[G] The Glossary definition of "Contingency" is not appropriate because the definition is too broad.

Balancing Authority

Definition

The ~~functional~~ responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports ~~contributes to~~ Interconnection frequency in real time.[19]

Relationships with Other Functional Entities

Ahead of Time

1. Receive generator Facility plans from Generator Operators within the Balancing Authority Area.
2. Receive operational data from Generator Operators within the Balancing Authority Area.
3. ~~1.~~ Receive~~s~~ operating and availability status of generating units ~~and operational plans and commitments~~ from Generator Operators ~~(including annual maintenance plans)~~ within the Balancing Authority Area.
4. ~~Receives annual maintenance plans from Generator Owners within the Balancing Authority Area.~~
5. ~~3.~~ Receive~~s~~ reliability evaluations from the Reliability Coordinator.
6. ~~Receives final approval or denial of a request for an Arranged Interchange from the Interchange Coordinators.~~
7. Compile~~s~~ ~~load~~Demand forecasts from Load-Serving Entities.
8. Develop~~s~~ ~~a~~Agreements with adjacent Balancing Authorities for ACE calculation parameters.
9. Submit~~s~~ integrated operational plans to the Reliability Coordinator for reliability evaluation and provides balancing information to the Reliability Coordinator for monitoring.
10. ~~Confirms~~ Receive Arranged Interchange from~~with~~ Interchange Coordinators.
11. ~~Confirms~~ Send approval or denial of Arranged Interchange based on meeting ~~r~~Ramping requirements ~~capability~~ to ~~with~~ Interchange Coordinators.
12. ~~9.~~10. Receive notice of final approval or denial of Arranged Interchange becoming Confirmed Interchange from the Interchange Coordinator.
13. ~~10.~~11. Implement~~s~~ generator commitment and dispatch schedules from the Load-Serving Entities ~~and Generator Operators~~ who have arranged for ~~generation~~ resources within the Balancing Authority Area.
14. ~~11.~~12. Acquires Interconnected Operations Services (IOS) ~~reliability-related services~~ from Generator Operator.
15. ~~12.~~13. Receive~~s~~ dispatch adjustments from Reliability Coordinators to prevent exceeding limits.
16. Receives generator information from Generator Owners including unit maintenance schedules and retirement plans.
17. ~~13.~~15. Receive reports on frequency regulating equipment from Generator Operators within the Balancing Authority Area.

[19] Definition of Balancing Authority from the NERC Glossary of Terms (as of May 15, 2016).

~~14.~~16. Receive~~s~~ information from Load-~~-~~Serving Entities on self-provided Interconnected Operations Services (IOS) ~~reliability-related services~~.

~~15.~~17. Coordinate~~s~~ ~~system~~ restoration plans (*i.e.*, any combination of generation, Transmission or distribution components) with the Transmission Operator.

~~16.~~18. Provide~~s~~ ~~generation~~ resource dispatch to Reliability Coordinators.

Real-time

~~17.~~19. Coordinate~~s~~ use of Interruptible Demand ~~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.~~20. Receive~~s~~ loss allocation from Transmission Service Providers (for repayment with in-kind losses).

~~19.~~21. Receive~~s~~ Real-time operating information from the Transmission Operator, adjacent Balancing Authorities and Generator Operators.

~~20.~~22. Receive~~s~~ operating information from Generator Operators.

~~21.~~23. Provide~~s~~ Real-time operational information for Reliability Coordinator monitoring.

~~22.~~24. Receive~~s~~ reliability alerts from Reliability Coordinator.

~~23.~~25. Comply~~ies~~ with reliability-related requirements (*e.g.*, reactive requirements, location of operating reserves) specified by Reliability Coordinator.

~~24.~~26. Verify~~ies~~ implementation of ~~e~~Emergency procedures to Reliability Coordinator.

27. Inform~~s~~ Reliability Coordinator and Interchange Coordinators of Confirmed Interchange changes (*e.g.*, due to Demand ~~generation~~ or resource~~load~~ interruptions) involving its Balancing Authority Area.

~~25.~~28. Receive Confirmed Interchange revisions (including Curtailments) from Interchange Coordinators.

~~26.~~29. Direct~~s~~ resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in ~~r~~Real-~~-~~time.

~~27.~~30. Request ~~Directs~~ Transmission Operator (or Distribution Provider) to reduce voltage to lower Demand or shed load if needed to ensure balance within its Balancing Authority Area.

~~28.~~31. Direct~~s~~ Generator Operators to implement re-dispatch for congestion management as directed by the Reliability Coordinator.

~~29.~~32. Implements corrective actions and ~~e~~Emergency procedures as directed by the Reliability Coordinator.

~~30.~~33. Implement~~s~~ ~~system~~ restoration plans (*i.e.*, any combination of generation, Transmission or distribution components) as directed by the Transmission Operator.

~~31.~~34. Direct~~s~~ Transmission Operator to implement flow control devices.

~~31. Receives information of Implemented Interchange and Confirmed Interchange curtailments from Interchange Coordinator.~~

After the hour

~~32.~~35. Confirm~~s~~ Implemented Interchange with Confirmed Interchange provided by the Interchange Coordinators after the hour for "checkout."

36. Confirm~~s~~ Implemented Interchange and Confirmed Interchange with adjacent Balancing Authorities

after the hour for “checkout.”

~~33.~~37. Request record of individual Confirmed Interchange from Interchange Coordinator.

Market Operations and Market Operator (Resource Integrator)

Market Operations

Tasks

1. The m~~M~~arket ~~O~~operations function, its tasks, and the interrelationships with other entities are included in the Functional Model only as an interface point of reliability ~~F~~functions with commercial functions.

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 oOperator tasks and relationships are specific to a particular market design and will depend on the market structure over which the ~~M~~market ~~O~~operator presides.

Transmission Operations and Transmission Operator

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[20] classed as ~~t~~Transmission assets, which may include the ~~t~~Transmission lines connecting a generating plant to the ~~t~~Transmission system, associated protective relaying systems and Remedial Action Schemes~~Special Protection Systems~~.
3. Develop ~~s~~System limitations (*e.g.*, ~~, such as~~ System Operating Limits) ~~and Total Transfer Capabilities,~~ and operate within those limits.
4. Develop and implement ~~e~~Emergency procedures.
5. Develop and implement ~~s~~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 Real Power, Reactive Power and voltage ~~flow control devices within the transmission area~~ to maintain reliability.

~~9. Deploy reactive resources to maintain transmission voltage within defined limits.~~

~~10.~~9. Determine the Transmission capability that supports the Reliable Operation of the Transmission Operator Area.

~~11.~~10. Operate or direct the operation of Transmission Facilities in its TOP Area.

11. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.

12. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

[20] The Glossary definition of "Facility" is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application to include responsibilities for non-BES elements.

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.[21] ~~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 ~~t~~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 the reliability of the ~~t~~Transmission system~~operations~~, but have different responsibilities ~~scopes~~. The Transmission Operator shares a role in monitoring the Transmission system with ~~scope is narrower than~~ the Reliability Coordinator and additionally, has the operational responsibility for the Transmission system area under its purview.~~and the Transmission Operator does not necessarily "see" very far beyond its own boundaries. Therefore, t~~ The Transmission Operator can calculate System Operating Limits, but does not necessarily have the Wide-area view of the Reliability Coordinator ~~will not necessarily~~ necessary to calculate Interconnection Reliability Operating Limits.~~, which requires the wider scope of the Reliability Coordinator.~~

Relationships with Other Functional Entities

Ahead of Time

1. Coordinate~~s~~ restoration plans with Reliability Coordinator, Transmission Operators, Balancing Authorities, and Distribution Providers.
2. Receive~~s~~ maintenance requirements and construction plans and schedules from the Transmission Owners and Generation Owners.
3. Receive~~s~~ Interconnection Reliability Operating Limits as established by the Reliability Coordinator.
4. Receive~~s~~ reliability evaluations from the Reliability Coordinator.
5. Develop~~s~~ agreements (Operating Plans, procedures, and processes) with adjacent Transmission Operators ~~for joint transmission facilities~~.
6. Define~~s~~ Total Transfer Capabilities and System Operating Limits based on facility[22] information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator.
7. Arrange~~s~~ for Interconnected Operations Services (IOS) ~~reliability related services~~ from Generator Operators (*e.g.*, voltage schedules, VAR Demand schedule).
8. Develop~~s~~ contingency plans, and monitors operations of the ~~t~~Transmission facilities within the Transmission Operator Area control and as directed by the Reliability Coordinator.
9. Provide~~s~~ facility and operating information to the Reliability Coordinator.
10. Provide~~s~~ to the Transmission Planner information on the capability to ~~c~~Curtail (reduce) and shed load during ~~e~~Emergencies.

[21] Definition of Transmission Operator from the NERC Glossary of Terms (as of May 15, 2016).

[22] The Glossary definition of "Facility" is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application to include responsibilities for non-BES elements.

11. Provide~~s~~ Total Transfer Capabilities, ~~and~~ System Operating Limits, and methodology for calculating ~~to, and coordinates~~ Available Transfer Capability for respective Transmission paths to~~with,~~ Transmission Service Provider.

12. Receive~~s~~ operating and availability status of generating units from Generat~~or~~ion Operators including status of automatic voltage regulators and power system stabilizers.

~~12.~~13. Receive operational data from Generator Operators.

~~13.~~14. Develop~~s~~ operating agreements or procedures with Transmission Owners.

Real-time

~~14.~~15. Coordinates load shedding with, or as directed by, the Reliability Coordinator.

~~15.~~16. Provide~~s~~ Real-time operations information to the Reliability Coordinator and Balancing Authority.

~~16.~~17. Notify~~ies~~ Generator Operators of ~~t~~Transmission system problems (*e.g.*, voltage limitations or equipment overloads that may affect generator operations).

~~17.~~18. Request~~s~~ Reliability Coordinator to assist in mitigating equipment overloads. (*e.g.*, re-dispatch, ~~t~~Transmission loading relief).

~~18.~~19. Deploy~~s~~ reactive resources from Transmission Owners, ~~and~~ Generator Owners, and Distribution Providers ~~-~~to maintain acceptable voltage profiles.

~~19.~~20. Direct~~s~~ Distribution Providers to shed load if needed to ensure reliability within the Transmission Operator Area.

~~20.~~21. Implement~~s~~ flow control device operations for those ties under the Transmission Operator's purview as directed by the Balancing Authorities or Reliability Coordinator.

~~21.~~22. Receive~~s~~ reliability alerts from Reliability Coordinator.

~~22.~~23. Direct~~s~~ Balancing Authorities and Distribution Providers to implement system restoration plans.

~~23.~~24. Receive Real-time operating information from Generator Operators.

Interchange and Interchange Coordinator

Interchange

Tasks

1. Receive completed Request for Interchange (RFI) (*i.e.*, valid source and sink, Transmission arrangements) ~~an Arranged Interchange~~.
2. Transition RFI to ~~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. Forward Arranged Interchange to entities for ~~Coordinate (*i.e.*, collect and consolidate)~~ approval, change, or~~and~~ denial ~~requests for an Arranged Interchange to become Confirmed Interchange~~. ~~Approvals may be explicit or by exception.~~
4. Collect approvals and denials ~~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. Submit Arranged Interchange for Curtailments and re-dispatch implementation requests.

~~7.~~8. Maintain record of an individual Confirmed Interchange.

~~8.~~9. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.

~~9.~~10. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

Interchange Coordinator

Definition

The ~~functional~~ responsible entity that authorizes ~~ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates~~ implementation of valid and balanced Interchange Schedules ~~Confirmed Interchange~~ between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.[23]

Relationships with Other Functional Entities

Ahead of Time

1. Receive~~s~~ Requests for ~~Arranged~~ Interchange from Generation Owner, Purchasing-Selling Entity, and Load-~~-~~Serving Entit~~y~~ies~~s~~.
2. Submit~~s~~ ~~request for an~~ Arranged Interchange to become Confirmed Interchange to the Balancing Authorities and Transmission Service Providers for approvals.
3. Receive~~s~~ approval or denial from Transmission Service Providers of ~~t~~Transmission arrangement(s) for Arranged Interchange.
4. Receive~~s~~ approval or denial from Balancing Authorities of the ability to meet ~~r~~Ramping requirements for submitted Arranged Interchange.
5. Receives approval from Generation Owners, Purchase-Selling Entities, or Load-Serving Entities for any revised Arranged Interchange.
6. Communicate~~s~~ final approval or denial of a request for an Arranged Interchange to become Confirmed ~~i~~Interchange to the Reliability Coordinator, Balancing Authorities, Transmission Service Providers, Generation Owners, ~~and~~ Purchasing-Selling Entities, and Load-Serving Entities for implementation ~~and NERC identified reliability analysis services~~.

Real-time

7. Receive reliability alerts from the Reliability Coordinators.
8. Receive~~s~~ ~~c~~Curtailments and re-dispatch implementation requests from Reliability Coordinators and submits ~~for an~~ Arranged Interchange.
9. Receive~~s~~ information on Confirmed Interchange interruptions from the Balancing Authorities and communicates the Confirmed Interchange status to Balancing Authorities, Transmission Service Providers, Reliability Coordinators, Generation Owner, and Purchasing-Selling Entities, and ~~/~~Load- Serving Entities.
10. Inform~~s~~ Reliability Coordinators, Balancing Authorities, Transmission Service Providers, Generation Owners, Purchasing-Selling Entities, and~~/~~ Load-Serving Entities~~, Reliability Coordinators, and Balancing Authorities~~ of Confirmed Interchange revisions (including ~~c~~Curtailments).

After the hour

11. ~~Maintains and p~~Provide~~s~~ a record of individual Confirmed Interchange to requesting ~~for which it coordinated with the~~ Balancing Authorities.

[23] Definition of Interchange Authority from the NERC Glossary of Terms (as of May 15, 2016). The Glossary uses the term "Interchange Authority" whereas the Functional Model uses the term "Interchange Coordinator."

12. Coordinate~~s~~ Confirmed Interchange with Balancing Authorities after the hour for "checkout."

Transmission Service and Transmission Service Provider

Transmission Service

Tasks

1. Receive ~~t~~Transmission ~~s~~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 ~~t~~Transmission ~~s~~Service according to the requirements of the tariff (*e.g.*, OASIS).
2. Determine and post available transfer ~~capability~~ capacity values.
3. Approve or deny ~~t~~Transmission ~~s~~Service requests.
4. Approve or deny Arranged Interchange from ~~t~~Transmission ~~s~~Service arrangement perspective.
5. Allocate ~~t~~Transmission losses (MWs or funds) among Balancing Authority Areas.
6. Acquire Ancillary Services to support Transmission Service.
~~5.~~7. Update information that is relevant to a long-term Transmission Service arrangement.

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.[24]

Relationships with Other Functional Entities

Ahead of Time

1. Receive the methodology to determine available transfer capacity from the Transmission Operator.

~~1.~~2. Receive~~s~~ Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits from ~~Planning Coordinator,~~ the Transmission Planner~~,~~ Transmission Operator and Reliability Coordinator, and coordinates ~~A~~available ~~T~~transfer capacity~~Capability~~ with these entities and other Transmission Service Providers.

~~2. Receives transmission Facility Ratings from Transmission Owners.~~

3. Receive~~s~~ ~~t~~Transmission expansion plans identified by the Transmission Planner(s) ~~Planning Coordinator~~ to help determine ability to accommodate long-term ~~t~~Transmission ~~s~~Service requests.

4. Arrange for providers of Ancillary Services, and notify the Transmission Operator and Balancing Authority.

5. ~~Approves~~ Accept or ~~denies~~ decline ~~t~~Transmission ~~s~~Service requests from Purchasing-Selling Entities, Generator Owners, and Load-Serving Entities.

~~6. Confirms validity of transmission service requests indicated in the Arranged Interchange with Interchange Coordinators.~~

~~7.~~6. Develop~~s~~ ~~a~~Agreements or procedures with Transmission Owners.

7. Receive~~s~~ ~~final approval or denial of~~ Arranged Interchange from Interchange Coordinator.

8. Send approval or denial of Arranged Interchange to Interchange Coordinator based on meeting Transmission Service arrangements.

9. Receive notice of final approval or denial of Arranged Interchange becoming Confirmed Interchange from Interchange Coordinator.

10. Receives updated information from Balancing Authority, Resource Planner, Load-Serving Entity, Purchasing-Selling Entity, and market operator for long-term Transmission Service arrangement.

Real-time

~~8.~~11. Receive~~s~~ Confirmed Interchange revisions ~~implementation~~ (including ~~c~~Curtailments) from the Interchange Coordinators.

12. Receive Confirmed Interchange Interruption status from Interchange Coordinator.

~~9.~~13. Receive~~s~~ reliability alerts from Reliability Coordinator.

14. Provide~~s~~ loss allocation to Balancing Authorities.

[24] Definition of Transmission Service Provider from the NERC Glossary of Terms (as of May 15, 2016).

15. Notify the Transmission Operator and Balancing Authority of changes to Ancillary Services.

Transmission Ownership and Transmission Owner

Transmission Ownership

Tasks

1. Develop interconnection ~~a~~Agreements.
2. Establish ~~r~~Ratings of ~~t~~Transmission facilities.~~-~~[25]
3. Maintain ~~t~~Transmission facilities and rights-of-way.
4. Design and install owned facilities classified as ~~t~~Transmission and obtain associated rights-of-way.
5. Design and authorize maintenance of ~~t~~Transmission protective relaying systems and ~~Special Protection Systems~~Remedial Action Schemes.
6. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
7. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

[25] The Glossary definition of "Facility" is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application for non-BES elements.

Transmission Owner

Definition

The ~~functional~~ entity that owns and maintains transmission ~~f~~Facilities.[26]

Relationships with Other Functional Entities

1. Coordinate~~s~~ with Transmission Planners, ~~and~~ the Planning Coordinator, ~~Generator Owners,~~ and other Transmission Owners, ~~and Load-Serving Entities~~ desiring to connect with the Transmission system under the purview of the Transmission Owner. ~~the Bulk Electric System.~~
2. Receive~~s~~ approved ~~t~~Transmission expansion plans from the Transmission Planner.
3. Develop~~s~~ agreements or procedures with the Transmission Service Providers.
4. Develop~~s~~ operating agreements or procedures with the Transmission Operators, Reliability Coordinators and Distribution Providers.
5. Develop~~s~~ agreements with adjacent Transmission Owners for joint ~~t~~Transmission facilities.
6. Provide~~s~~ ~~t~~Transmission expansion plans and changes to the Planning Coordinator and Transmission Planners.
7. Provide~~s~~ ~~t~~Transmission Facility Ratings to Transmission Operators, Reliability Coordinators, Transmission Service Providers, Distribution Providers, Transmission Planners, and Planning Coordinator.
8. Provide~~s~~ maintenance and construction plans and schedules to the Reliability Coordinator, Transmission Operator, and Transmission Planner.
9. Coordinate and ~~D~~develop~~s~~ interconnection agreements with the Distribution Providers, ~~and~~ Generation Owners, and Load Serving Entities desiring to connect with the Transmission system under the purview of the Transmission Owner ~~for connecting to the Bulk Electric System~~.
10. Provide~~s~~ reactive resources to Transmission Operators.
11. Revise~~s~~ ~~t~~Transmission maintenance plans as requested by a Transmission Operator or the Reliability Coordinator.

[26] Definition of Transmission Owner from the NERC Glossary of Terms (as of May 15, 2016).

Distribution and Distribution Provider

Distribution

Tasks

1. Provide and operate electrical delivery ~~f~~Facilities between the ~~t~~Transmission system and the ~~E~~end-use ~~C~~customer or distribution-connected energy resource.
2. Identify and characterize its connected load and energy resources.
3. ~~2.~~Implement voltage reduction.
4. ~~3.~~Design and maintain protective relaying systems, under-frequency load-shedding systems, under-voltage load-shedding systems, and Remedial Action Schemes~~Special Protection Systems~~ that interface with the ~~t~~Transmission system.
5. ~~4.~~Provide and implement load-shed capability.
6. ~~5.~~Maintain voltage and power factor within specified limits at the interconnection point.
7. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
8. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

Distribution Provider

Definition

The functional entity that 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.[27] ~~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 ~~e~~Electrical ~~e~~Energy ~~to the End-use Customer~~ from the ~~t~~Transmission system to the ~~E~~end-use ~~C~~customer. ~~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 ~~e~~Emergency action.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinate~~s~~ with Transmission Planners on interconnected load and energy resources to support ~~t~~Transmission analysis~~expansion~~.
2. Coordinate~~s~~ ~~s~~System restoration plans with Transmission Operator.
3. Coordinate~~s~~ with ~~E~~end-use ~~C~~customers, distributed energy resources, and Load-Serving Entities to identify new ~~f~~Facility connection needs.
4. Develop interconnection agreements with Transmission Owners on a ~~f~~Facility basis.
5. Provide~~s~~ 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.
7. Provide protective relaying systems, under-frequency load-shedding systems, under-voltage load-shedding systems, and Remedial Action Schemes as defined by the Transmission Planner and Planning Coordinator.

Real-time

8. Obtain voltage and power factor requirements from the Transmission Operator.

~~6.~~9. Implement~~s~~ voltage reduction and shed~~s~~ load as directed by the Transmission Operator or Balancing Authority.

~~7.~~10. Implement~~s~~ ~~s~~System restoration plans as coordinated by the Transmission Operator.

~~8.~~11. Direct~~s~~ Load-Serving Entities to communicate requests for voluntary load ~~c~~Curtailment.

[27] Definition of Distribution Provider from the NERC Glossary of Terms (as of May 15, 2016).

Generator Operation and Generator Operator

Generator Operation

Tasks

1. Formulate daily generation plan.
2. Report operating and availability status of generator Facility(ies) ~~units~~ and related equipment, such as automatic voltage regulator~~s~~ equipment, power system stabilizer equipment and frequency regulating equipment.
3. Operate generator~~s~~ Facility(ies) to provide ~~r~~Real Power and ~~r~~Reactive ~~p~~Power or Interconnected Operations Services ~~reliability-related services~~ in accordance with ~~per~~ contracts or arrangements.
4. Monitor the status of generator~~ing~~ ~~f~~Facility(ies).
5. Support Interconnection frequency and voltage.
6. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
7. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

Generator Operator

Definition

The ~~functional~~ entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services~~reliability related services~~.[28]

Relationships with Other Functional Entities

Ahead of Time

1. Provide~~s~~ generation commitment plans to the Balancing Authority.
2. Provide~~s~~ Balancing Authority and Transmission Operators with requested amount of Interconnected Operations Services (IOS)~~reliability-related services~~.
3. Provide~~s~~ availability and operating ~~and availability~~ status of generator~~ing~~ ~~units~~ Facility(ies), to Reliability Coordinator, Balancing Authority and Transmission Operators for reliability analysis.
4. Report~~s~~ status of automatic voltage regulating equipment and power system stabilizer equipment ~~or frequency regulating equipment to~~ Transmission Operators.
5. Report on frequency regulating equipment to Balancing Authority.
6. Provide~~s~~ operational data to Reliability Coordinator, Balancing Authority and Transmission Operator.
7. ~~Receives reliability analyses from Reliability Coordinator.~~
8. Receive~~s~~ notice from Purchasing-Selling Entity if Arranged Interchange approved or denied.
9. Receive~~s~~ reliability alerts from Reliability Coordinator.
10. Receive~~s~~ notification of ~~t~~Transmission system problems from Transmission Operators.

Real-time

11. Provide~~s~~ Real-time operating information to the Transmission Operators and the required Balancing Authority.
12. Adjust~~s~~ ~~r~~Real Power and ~~r~~Reactive ~~p~~Power as directed by the Balancing Authority and Transmission Operators.

[28] Definition of Generator Operator from the NERC Glossary of Terms (as of May 15, 2016).

Generator Ownership and Generator Owner

Generator Ownership

Tasks

1. Establishes generatiorng facilities Facility rRatings, limits, and operating requirements.
2. Designs and authorizes maintenance of the generatiorn plant protective relaying systems, protective relaying systems on the tTransmission lines connecting the generatiorn plant to the tTransmission system, and Remedial Action Schemes (RAS)Special Protection Systems related to the generator.
3. Performs or authorizes Maintains maintenance of owned generatoring fFacilities.
4. Provides verified generatiorng fFacility performance characteristics / data.
5. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
6. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

Generator Owner

Definition

The ~~functional~~ entity that owns and maintains generating Facility(ies)~~units~~.[29]

Relationships with Other Functional Entities

Ahead of Time

1. Provide~~s~~ generator Facility(ies) information to the Transmission Operator, Reliability Coordinator, Balancing Authority, Transmission Planner, and Resource Planner.
2. Provide~~s~~ generator Facility(ies) ~~unit~~ maintenance schedules and generator Facility(ies) ~~unit~~ retirement plans to the Reliability Coordinator, Transmission Operator, Balancing Authority, Transmission Planner, and Resource Planner.
3. Develop~~s~~ ~~an~~ interconnection ~~a~~Agreement(s) with Transmission Owner on a ~~f~~Facility basis.
4. Receive~~s~~ approval or denial of ~~t~~Transmission ~~s~~Service request from Transmission Service Provider.
5. Provide~~s~~ Interconnected Operations Services ~~reliability related services~~ to Purchasing-Selling Entity pursuant to agreement.

~~6. Reports the annual maintenance plan to the Reliability Coordinator, Balancing Authority and Transmission Operator.~~

6. Revise~~s~~ the generator~~ion~~ maintenance plans as requested by the Balancing Authority, Transmission Operator, and Reliability Coordinator.
7. Submit Request for Interchange to the Interchange Coordinator.
8. Submit approval for original or revised Arranged Interchange to the Interchange Coordinator.
~~7.~~9. Receive communication that Arranged Interchange has become Confirmed Interchange from the Interchange Coordinator.

Real-time

10. Receive Confirmed Interchange Interruptions status from the Interchange Coordinator.
~~8.~~11. Receive Confirmed Interchange revisions (including Curtailments) from the Interchange Coordinator.

[29] Definition of Generator Owner from the NERC Glossary of Terms (as of May 15, 2016).

Purchasinge-Selling and Purchasinge-Selling Entity

Purchasinge-Selling

Tasks

1. Purchase and sell energy or capacity.
2. Arrange for ~~t~~Transmission ~~s~~Service that is required to implement an Interchange Transaction~~by tariffs~~.
3. Request implementation of Arranged Interchange.

Purchasinge-Selling Entity

Definition

The ~~functional~~ entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services~~reliability related services~~. Purchase-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.[30]

Relationships with Other Functional Entities

Ahead of Time

1. Arrange for energy and capacity from Generator Owners.
2. Arrange~~s~~ for ~~t~~Transmission ~~s~~Service from Transmission Service Providers and makes arrangements for self-provided Interconnected Operations Services ~~reliability-related services~~ with Generator Owners or Load-Serving Entities.
3. Submit~~s~~ Requests For Interchange to Interchange Coordinators.

~~3.~~4. Submit approval for original or revised Arranged Interchange to Interchange Coordinator.

~~4. Notifies Generator Operators and Load-Serving Entities if Arranged Interchange requests are approved or denied.~~

5. Receive~~s~~ communication that ~~final approval or denial of~~ Arranged Interchange has become Confirmed Interchange from the Interchange Coordinator.
6. Receive~~s~~ ~~load~~ Demand profiles and forecasts from Load-Serving Entities.

Real-time

7. Receive notice of Confirmed Interchange Interruptions from Interchange Coordinator.
8. Receive notice of Confirmed Interchange revisions (including Curtailments) from Interchange Coordinator.

~~7.~~9. Notify~~ies~~ Interchange Coordinators of Confirmed Interchange and Implemented Interchange cancellations or terminations.

~~8.~~10. Receive~~s~~ notice of Confirmed Interchange ~~c~~Curtailments from Interchange Coordinator.

[30] Definition of Purchasing-Selling Entity from the NERC Glossary of Terms (as of May 15, 2016).

Load-Serving and Load-Serving Entity

Load-Serving

Tasks

1. Collect individual load profiles and characteristics.
2. Identify capability for and communicate requests for voluntary load ~~c~~Curtailment.
3. Identify and communicate ~~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 the resources needed for ~~facilities and provide capability of~~ self-provided Interconnected Operations Services (IOS) ~~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 provide for Interconnected Operations Services~~reliability-related services~~.
7. Arrange for ~~Submits Requests For~~ Interchange ~~to Interchange Coordinators.~~
8. Manage resource portfolios to meet ~~demand~~ Demand and energy delivery requirements. ~~of End-use Customers.~~

Load-Serving Entity

Definition

~~The functional entity that~~ ~~secures~~ Secures energy and ~~t~~Transmission ~~s~~Service (and Interconnected Operations Services)~~reliability related services)~~ to serve the electrical demand and energy requirements of its end~~-~~use customers.[31]

Relationships with Other Functional Entities

Ahead of Time

1. Submit~~s~~ load data ~~profiles and characteristics, plans, and forecasts~~ as needed to the appropriate entity (*e.g.,* ~~-~~Balancing Authorities, ~~Purchasing-Selling Entities, Planning Coordinator,~~ and Resource Planners, and Transmission ~~Planners~~Service Provider) in accordance with applicable tariffs, interconnection agreements or other arrangements.
2. Coordinate with Distribution Provider to identify critical loads that are to be excluded from load-shedding. ~~Identifies new facility connection needs for End-use Customers.~~
3. Provides generation commitments and dispatch schedules to the Balancing Authority.
4. Provide~~s~~ information regarding~~as to~~ self-provided Interconnected Operations Services (IOS) ~~reliability-related services~~ to the Balancing Authority.
5. Provide~~s~~ necessary data ~~planned purchases~~ to the Resource Planner and Transmission Planner for ~~s~~System modeling and reliability evaluation.
6. Arrange~~s~~ for ~~t~~Transmission ~~s~~Service from Transmission Service Providers and makes arrangements for Ancillary Services ~~reliability-related services~~ with Generator Owners or Load-Serving Entities.
7. Submit~~s~~ Requests For Interchange to Interchange Coordinator~~s~~.

~~7.~~8. Submit approval for original or revised Arranged Interchange to Interchange Coordinator.

9. Receive communication that Arranged Interchange has become Confirmed Interchange from the Interchange Coordinator.

~~8.~~10. Notify~~ies~~ Generator Operators if Arranged Interchange requests are approved or denied.

~~9. Receives final approval or denial of Arranged Interchange from Interchange Coordinator.~~

~~10.~~11. Coordinate~~s~~ with Distribution Provider on identifying new ~~f~~Facility interconnection needs.

~~10. Receives notification from Purchasing-Selling Entity if Arranged Interchange requests approved or denied.~~

Real-time

~~11.~~12. Receive~~s~~ requests from the Reliability Coordinator, Balancing Authority, Transmission Operator, and Distribution Provider ~~-~~for voluntary load ~~c~~Curtailment.

~~12.~~13. Communicate requests for voluntary load ~~c~~Curtailment to end-use customers as directed by the Reliability Coordinator, Balancing Authority, Transmission Operator, and Distribution Provider.

[31] Definition of Load-Serving Entity from the NERC Glossary of Terms (as of May 15, 2016).

~~13. Notifies Interchange Coordinators of Confirmed Interchange cancellations or terminations.~~

14. Receive~~s~~ notice of Confirmed Interchange revisions (including ~~c~~Curtailments) from Interchange Coordinator.

~~14.~~15. Receive notice of Confirmed Interchange Interruptions from Interchange Coordinator.

Section IV: Version History

[This section will be completed prior to seeking final approval from the Standards Committee.]

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Issues and Directives

Project 2015-08 Emergency Operations

Project 2015-08 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Order no. 749: *"[N]ERC, in its comments about the term [unique tasks], states that it 'could promote the development of a guideline to aid registered entities in complying with Requirement R11.' The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations."*	FERC Order Number 749	The Project 2015-02 Emergency Operations Periodic Review Team (EOP PRT), as well as the Project 2015-08 Emergency Operations Standards Drafting Team (EOP SDT) determined (through conducted outreach and comment questions/responses during postings of periodic review templates, the project SAR, and project postings) that industry does not find ambiguity with the term "unique tasks." The industry understands "unique tasks" to be those tasks that are defined by the Transmission Operator (TOP), Transmission Owner (TO), and the Distribution Provider (DP). A rationale box was added to EOP-005-3, Rquirement R9 to clarify "unique tasks." **Rationale:** The intent of "unique tasks" are those tasks that are defined by the Transmission Operator, the Transmission Owner, and the Distribution Provider.
Clarify when system changes will trigger a requirement to update restoration plans. The joint staff review team recommends that measures be taken (including considering changes to the Reliability Standards) to address the need for updating restoration	FERC-NERC-Regional Entity Joint Review of Restoration	The Project 2015-08 EOP SDT revised EOP-005-3, Requirement R4 and the requirement parts. The references to unplanned permanent and planned permanent BES modifications that will change the ability to implement the Reliability Coordinator (RC)-approved restoration plan are intended to require a TOP to

Project 2015-08 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
plans for all system modifications that would change the implementation of an entity's restoration plan for an extended period of time, not just permanent or planned system modifications. In considering these measures, the kinds of events that may warrant an update to the system restoration plan should be identified, taking into account the length of time the system is affected, as well as the overall objective of ensuring that restoration plans are generally flexible enough so that system modifications can be addressed without continuous updates.	and Recovery Plans. **Section IV.E**	update and submit a restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan, the TOP's ability to implement the plan, or the RC's ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes or device changes that have no significance to the implementation of the plan.
Verification/testing of modified restoration plan. The joint staff review team recommends that measures be taken (including considering changes to the Reliability Standards) to address the need for re-verification of a system restoration plan when a system change precipitates the need to determine whether the plan's restoration processes and procedures, when implemented, will operate reliably, i.e., when needed to ensure that the restoration plan, when implemented, allows for restoration of the system within acceptable operating voltage and frequency limits.6 In considering such measures, the types of system changes that could impact reliable implementation of the restoration plan should be taken into account (e.g., identification of a new	FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans. **Section IV.G**	The EOP SDT discussed the recommendation to address the "…need for re-verification of a system restoration plan when a system change precipitates the need to determine whether the plan's restoration processes and procedures, when implemented, will operate reliably…" The TOP performs detailed testing at least every five years to ensure that its restoration plan accomplishes its intended function (EOP-005, Requirement R6). In addition, the TOP 1) has to annually review its restoration plan and submit it to its RC for approval, 2) when there are revisions that would change the TOP's ability to implement its restoration plan, these also have to be submitted to the RC for review, 3) include within its operations training program annual System restoration training

Project 2015-08 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
blackstart generator location or on redefinition of a cranking path).		for its System Operators, and 4) participate in RC restoration drills, exercises or simulations (EOP-005, Requirements R3, R4, R8, and R10). The RC 1) has to review its restoration plan within 13 calendar months of the last review, 2) has to review its neighboring RC's restoration plans and provide notice of any conflicts discovered, 3) has to review and approve/disapprove its TOP's restoration plans, 4) provide annual System Restoration training for its System Operators, and 5) conduct two System Restoration drills, exercises or simulations per calendar year (EOP-006, Requirements R3, R4, R5, R7, and R8). The recommendation pointed to system changes that could impact the viability of the plan. When the RC reviews the TOP restoration plan for annual approval/disapproval, the RC is the only entity that has the wide-area view of the entire System, and the RC is the only entity that can effectively complete this approval. The EOP SDT believes that since the TOP and RC have to meet multiple requirements, that both entities are continually reviewing and testing the viability of their restoration plans; and, therefore, no changes were made in EOP-005 based on the recommendation.
Operator training: Exercises on transferring control back to the balancing authority. The joint staff review team recommends that measures be taken (including considering changes to the Reliability Standards) to	FERC-NERC-Regional Entity Joint Review of	Since the Balancing Authority does not relinquish any BA authority to the TOP, language was revised in EOP-005-3, Requirement R1, Part 1.9 to the standard: "Processes for

Project 2015-08 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
address system restoration training and drilling for transitioning from transmission operator island control to balancing authority ACE/AGC7 control.	Restoration and Recovery Plans. **Section IV.H.**	transferring operations ~~authority~~ back to the Balancing Authority in accordance with the Reliability Coordinator's criteria."

Standard Development Timeline

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

Description of Current Draft

EOP-004-4 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015

Anticipated Actions	Date
45-day formal comment period with ballot	07/25/2016 – 09/08/2016
45-day formal comment period with additional ballot	09/26/2016 – 11/09/2016
10-day final ballot	12/01/2016 – 12/12/2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Event Reporting

2. **Number:** EOP-004-4

3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.

4. **Applicability:**

   4.1. Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as "Responsible Entity."

   4.1.1. Reliability Coordinator

   4.1.2. Balancing Authority

   4.1.3. Transmission Owner

   4.1.4. Transmission Operator

   4.1.5. Generator Owner

   4.1.6. Generator Operator

   4.1.7. Distribution Provider

5. **Effective Date:** See the Implementation Plan for EOP-004-4.

~~**6. Background:** NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:~~

~~1. CIP-001 could be merged with EOP-004 to eliminate redundancies.~~
~~2. Acts of sabotage have to be reported to the DOE as part of EOP-004.~~
~~3. Specific references to the DOE form need to be eliminated.~~
~~4. EOP-004 had some 'fill-in-the-blank' components to eliminate.~~

~~The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.~~

~~The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.~~

~~The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the "road map" that will be used by the DSR SDT in~~

~~updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.~~

~~**7. Standard-Only Definition:** None~~

B. Requirements and Measures

~~**Rationale for Requirement R1:** Text~~

R1. Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-~~2 3~~ 4 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-~~3~~4 Attachment 1 and in accordance with the entity responsible for reporting.

~~**Rationale for Requirement R2:** Text~~

R2. Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday~~ local time~~). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. Each Responsible Entity will have as evidence of reporting an event either a~~,~~ copy of the completed EOP-004-~~3~~ 4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday~~ local time~~). ~~(R2)~~

~~Rationale for Requirement R3:~~ ~~Text~~

~~**R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)~~

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

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

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirement~~s~~ R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirement~~s~~ R2~~, R3~~ and Measure M2~~, M3~~.

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 duration 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.

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity had an Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.
R2.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.

R #	Violation Severity Levels			
				OR The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.
~~R3.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.~~ ~~OR~~ ~~The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.~~ ~~OR~~ ~~The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.~~ ~~OR~~ ~~The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more.~~ ~~OR~~ ~~The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.~~

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: -systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Rationale for Attachment 1:

System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.

Generation loss: The EOP SDT discussed dispersed power producing resources and their generation loss due to weather patterns or fuel source unavailability, but NERC confirmed that reporting of generation loss would be used to report Forced Outages not weather patterns or fuel source unavailability for these resources.

Complete loss of Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information."

Complete loss of monitoring or control capability at a BES control center: Language revisions to: "Complete loss of monitoring or control at a BES control center for 30 continuous minutes or more" provides clarity to the "Threshold for Reporting" and better aligns with the ERO Event Analysis Process.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in action(s) to avoid a BES Emergency.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of ~~a~~ its Facility	~~BA,~~ TO, ~~TOP,~~ GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.
Physical threats to ~~a~~ its Facility	~~BA,~~ TO, ~~TOP,~~ GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at ~~a~~ its Facility. ~~Do not report theft unless it degrades normal operation of a Facility.~~
Physical threats to ~~a~~ its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at ~~a~~ its BES control center.
~~BES Emergency requiring public~~ Public appeal for load reduction	~~Initiating entity is responsible for reporting~~BA	~~Public appeal for load reduction event.~~Public appeal for load reduction to maintain continuity of the BES.
~~BES Emergency requiring system~~System-wide voltage reduction to maintain the continuity of the BES	~~Initiating entity is responsible for reporting~~TOP	System wide voltage reduction of 3% or more.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
~~BES Emergency requiring manual f~~Firm load shedding resulting from a BES Emergency	~~Initiating entity is responsible for reporting~~RC, BA, TOP	~~Manual firm~~ Firm load shedding ≥ 100 MW.
~~BES Emergency resulting in automatic firm load shedding~~	~~DP, TOP~~	~~Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or RAS).~~
BES Emergency resulting in ~~Voltage~~ voltage deviation on a Facility	TOP	~~Observed within its area a~~ A voltage deviation of ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.
~~IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)~~	~~RC~~	~~Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).~~
Uncontrolled ~~Loss~~ loss of firm load resulting from a BES Emergency	BA, TOP, DP	Uncontrolled ~~Loss~~ loss of firm load for ≥ 15 Minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA~~, GOP~~	Total generation loss, within one minute, of~~-~~: ≥ 2,000 MW ~~for entities~~ in the Eastern, ~~or~~ Western, or Quebec Interconnection OR ≥ 1,000 MW ~~for entities~~ in the ERCOT ~~or Quebec~~ Interconnection
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).
Unplanned BES control center evacuation	RC, BA, TOP	Unplanned evacuation from BES control center facility for 30 continuous minutes or more.
Complete loss of ~~voice communication~~Interpersonal Communication capability at a BES control center	RC, BA, TOP	Complete loss of ~~voice~~ Interpersonal ~~communication~~ Communication capability affecting a staffed BES control center for 30 continuous minutes or more.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Complete loss of monitoring or control capability at a BES control center	RC, BA, TOP	Complete loss~~Complete loss~~ of monitoring or control at ~~capability affecting~~ a BES control center for 30 continuous minutes or more. ~~such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.~~

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780. Also submit to other organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
Task		**Comments**
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):	
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:	
3.	Did the event originate in your system?	Yes ☐ No☐ Unknown ☐
4.	**Event Identification and Description:**	

EOP-004 Attachment 2: Event Reporting Form Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780. Also submit to other organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."	
Task	**Comments**
(Check applicable box) ☐ Damage or destruction of a Facility ☐ Physical Threat to ~~a~~ its Facility ☐ Physical Threat to ~~a~~ its BES control center ☐ Unplanned BES control center evacuation ☐ Public appeal for load reduction ☐ System-wide voltage reduction ☐ BES Emergency: ~~☐ public appeal for load reduction~~ ~~☐ system-wide voltage reduction~~ ☐ ~~manual~~ firm load shedding ☐ ~~automatic firm load shedding~~voltage deviation on a Facility ☐ uncontrolled loss of firm load ~~☐ Voltage deviation on a Facility~~ ~~☐ IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer~~	Written description (optional):

EOP-004 Attachment 2: Event Reporting Form Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780. Also submit to other organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."	
Task	**Comments**
~~Paths (WECC only)~~ ☐ ~~Loss of firm load~~ ☐ System separation ☐ Generation loss ☐ Complete loss of off-site power to a nuclear generating plant (grid supply) ☐ Transmission loss ☐ ~~unplanned~~ Unplanned BES control center evacuation ☐ Complete loss of ~~voice~~ Interpersonal ~~communication~~ Communication capability at a BES control center ☐ Complete loss of monitoring or control capability at a BES control center	

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.	

Guideline and Technical Basis

~~**Distribution Provider Applicability Discussion**~~

~~The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the "Threshold for Reporting" for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more that 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.~~

Multiple Reports for a Single Organization

For entities that have multiple registrations, the ~~DSR SDT intends~~requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

~~**Summary of Key Concepts**~~

~~The DSR SDT identified the following principles to assist them in developing the standard:~~

- ~~Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System~~
- ~~Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements~~
- ~~Establish clear criteria for reporting~~
- ~~Establish consistent reporting timelines~~
- ~~Provide clarity around who will receive the information and how it will be used~~

~~During the development of concepts, the DSR SDT considered the FERC directive to "further define sabotage". There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to reporting events. The term "sabotage" is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events~~

~~as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.~~

~~The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.~~

~~The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.~~

~~**Data Gathering**~~

~~The requirements of EOP-004-1 require that entities "promptly analyze Bulk Electric System disturbances on its system or facilities" (Requirement R2). The requirements of EOP-004-3 specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-3 may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.~~

Law Enforcement Reporting

The reliability objective of EOP-004-~~3~~ 4 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry
- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC

- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

~~**Present expectations of the industry under CIP-001-1a:**~~

~~It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have led to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.~~

~~**Coordination of Local and State Law Enforcement Agencies with the FBI**~~

~~The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.~~

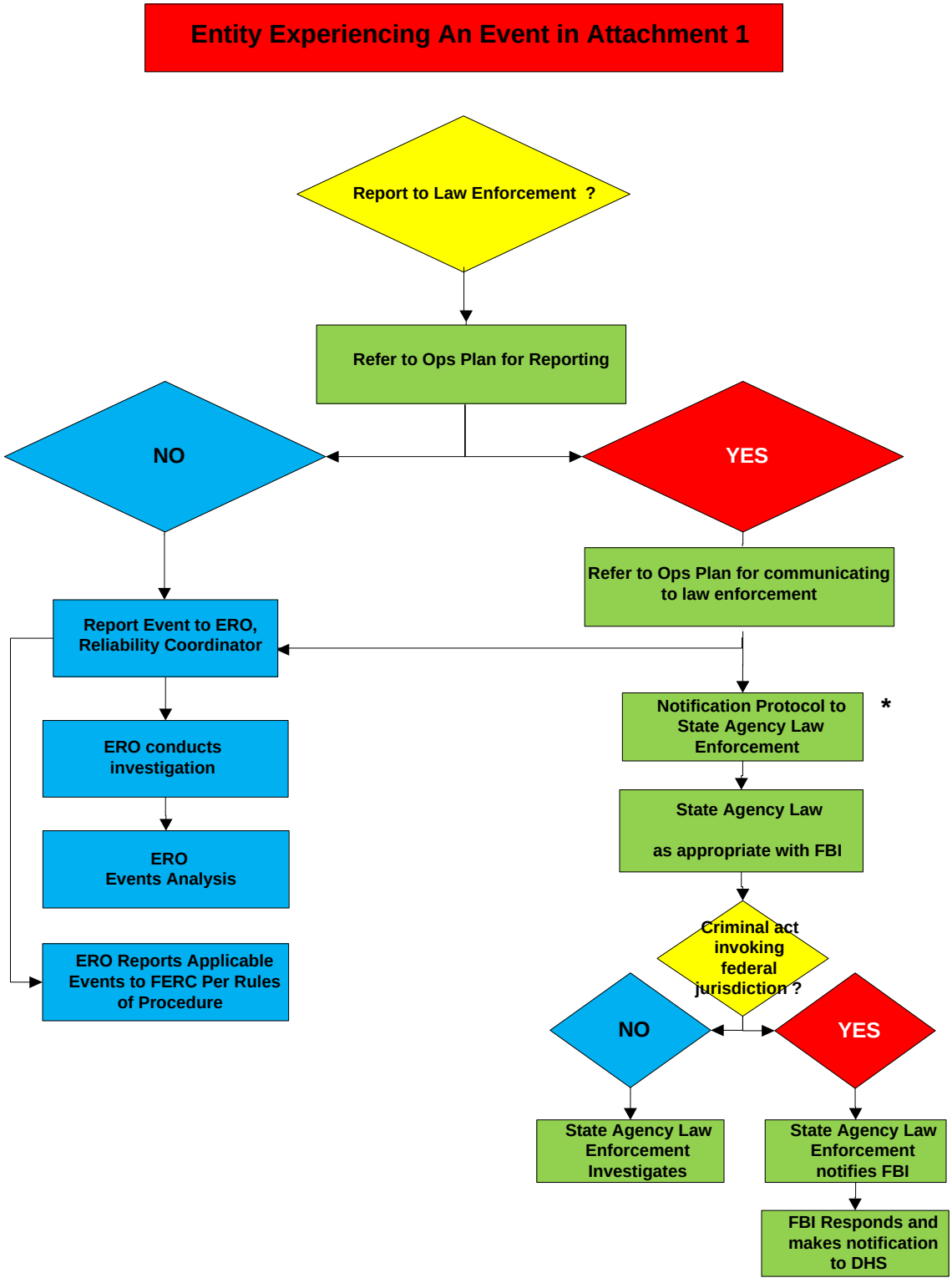
~~**Coordination of Local and Provincial Law Enforcement Agencies with the RCMP**~~

~~A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).~~

~~**A Reporting Process Solution – EOP-004**~~

~~A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.~~

Example of Reporting Process including Law Enforcement



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts

Introduction

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.

The standards listed under the SAR are:

CIP-001 — Sabotage Reporting

EOP-004 — Disturbance Reporting

The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.

The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.

Summary of Concepts and Assumptions:

The Standard:

- Requires reporting of "events" that impact or may impact the reliability of the Bulk Electric System
- Provides clear criteria for reporting
- Includes consistent reporting timelines
- Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting
- Provides clarity around of who will receive the information

Discussion of Disturbance Reporting

Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.
3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and

~~developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).~~

~~*Discussion of Event Reporting*~~

~~There are situations worthy of reporting because they have the potential to impact reliability.~~

~~Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.~~

~~Examples of such events include:~~

~~Bolts removed from transmission line structures~~

~~Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)~~

~~Destruction of Bulk Electric System equipment~~

~~**What about sabotage?**~~

~~One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *". . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event."*~~

~~Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.~~

~~Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.~~

Potential Uses of Reportable Information

General situational awareness, correlation of data, trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information as known at the time of the report. Further data gathering necessary for analysis is provided for under the ERO Event Analysis Program and the NERC Rules of Procedure. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination

of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

~~Event analysis, correlation of data, and trend identification are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information at the time of the report. Further data gathering necessary for event analysis is provided for under the Events Analysis Program and the NERC Rules of Procedure. Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.~~

~~**Collection of Reportable Information or "One stop shopping"**~~

~~The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.~~

~~The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.~~

~~ill assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.~~

Rationale

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

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Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-004-03, Requirement R3 **R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*	Recommended for retirement.	The EOP SDT recommends retirement of Requirement R3 under Criterion B1, administrative; the R3 requirement in EOP-004-3 requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome. Contact lists are administrative in nature.

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **EOP-004-4 – Event Reporting**. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines. The Emergency Operations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

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

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

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

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

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

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

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

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

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

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

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

VRF Justifications for EOP-004-4, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time frame to have an event reporting Operating Plan. The assignment of the Lower VRF was made based on the premise that failure to have an event reporting Operating Plan would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. This is mainly an administrative requirement and thus meets NERC's criteria for a Lower VRF.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report**

VRF Justifications for EOP-004-4, R1	
Proposed VRF	**Medium**
	R1 requires the entity to have an event reporting Operating Plan that is consistent with FERC guideline G1 regarding Operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective, which is to have an event reporting Operating Plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-004-4, R1			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity had an Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.

VRF Justifications for EOP-008-2, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event operating plan Operating Plan and mirrors the Requirements of EOP-004-3 with some minor edits. The VSL's for R1 were not revised. The VSL's for this requirement meet 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	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF Justifications for EOP-008-2, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-004-4, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in Operations Assessment time frame that requires entities to report events per their Operating Plan. 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. .
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the entity to report events per their Operating Plan. A violation of this requirement has been assigned a Medium VRF, consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned, so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R2 uses similar language from EOP-004-3, Requirement R2, and the VRF remains unchanged from earlier versions.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to report events per the Operating Plan would not be expected to have an adverse impact on the bulk power system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective and only one VRF was assigned.

VSLs for EOP-004-4, R2			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.

VSL Justifications for EOP-004-4, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event reporting Operating Plan and reporting events, and Requirement 2 language of EOP-004-4 is only slightly changed from EOP-004-3. The VSL's for this requirement meet 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	Guideline 2a: The VSL assignment is for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-004-4, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

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Standards Authorization Request Form

When completed, email this form to:
sarcomm@nerc.net

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard	
Proposed Standard:	Project 2015-10 Single Points of Failure TPL-001 SPCS and SAMS recommendations in response to FERC Order No. 754 (TPL-001-4)
Date Submitted:	October 05, 2015

SAR Requester Information			
Name:	Philip B. Winston, PE and John M Simonelli		
Organization:	Southern Company and ISO New England, Inc., respectively.		
Telephone:	404-608-5989--primary	E-mail:	pbwinsto@southernco.com--primary

SAR Type (Check as many as applicable)	
☐ New Standard	☐ Withdrawal of existing Standard
☒ Revision to existing Standards	☐ Urgent Action

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Modifications have been ~~identified~~recommended to Reliability Standard TPL-001-4 based on the following: Item 1: The System Protection and Control Subcommittee (SPCS) and the System Modeling and Analysis Subcommittee (SAMS) conducted a comprehensive assessment of the study of protection system single

SAR Information

points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action.

As such, regarding single points of failure in protection systems, the SPCS and the SAMS make the following recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process identified in the NERC Rules of Procedure:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and
  - Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.
- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase "or a relay failure[13]" from items a, b, c, and d to create distinct events only for stuck breakers.
  - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure[13]" with "a component failure of a Protection System[13]."
- Replace footnote 13 in TPL-001-4 with, "The components from the definition of "Protection System" for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single-station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."[1]
- Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults with the described component failures of a Protection System[13] that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

[1] See Order 754 (NERC website) Requests for Clarifications and Responses (http://www.nerc.com/pa/Stand/Order%20754%20DL/Order_754-Requests_for_Clarification_and_Responses_July2013.pdf).

SAR Information
~~Item 2: In addition, on October 17, 2013 the Commission issued Order No. 786, which included two directives related to TPL-001-4. The two directives are as follows:~~ ~~Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six-month threshold could exclude planned maintenance outages of significant facilities from future planning assessments~~ ~~Paragraph 89 directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4."~~ Item ~~3~~2: Further, references to MOD-010 and MOD_012 in Requirement R1 would need to be replaced with MOD-032 due to July 2016 retirement of those standards. In addition, on October 17, 2013 the Commission issued Order No. 786, which included two directives related to TPL-001-4. The two directives are as follows: • Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six-month threshold could exclude planned maintenance outages of significant facilities from future planning assessments • Paragraph 89 directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4." Purpose or Goal (How does this request propose to address the problem described above?): The ~~primary~~ goal of this SAR is to: 1. Consider the~~ appoint a Standard Drafting Team (SDT) to address~~ recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) as identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request"; 2. Address the two FERC directives from Order No. 786; and 3. Update the references to the MOD Reliability Standards in TPL-001. ~~."~~ Identify the Objectives of the proposed standards' requirements (What specific reliability deliverables are required to achieve the goal?): Provide clear, unambiguous requirements and Results-based Reliability Standards that will: (1) reflect ~~condiseration~~consideration of~~standards to address~~ the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request;" (ii) address the two FERC directives from Order No. 786 ~~citd~~cited above; and (iii) and update the references to the MOD Reliability Standards cited in TPL-001. ~~."~~

SAR Information
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall consider the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request", address the two FERC directives, update the references to the MOD Standards,~~"~~ and revise standards, requirements, attachments, Violation Risk Factors, Violation Severity Levels, and implementation plans as appropriate. The SDT shall consider retirements to requirements under Paragraph 81 criteria. In addition, the SDT shall work with compliance on an accompanying RSAW to address each of the standard's requirements and measures.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDTs execution of this SAR requires the SDT to consider~~address~~ the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request." This~~ The SDTs execution of this SAR would, in addition, consider retirements to requirements under Paragraph 81 criteria. The SPCS and SAMS~~ report ~~titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request"~~ is incorporated in its entirety into this SAR~~,~~ so as not to unnecessarily repeat or paraphrase the substance of the report. In addition, the SDTs execution of this SAR would consider retirements to requirements under Paragraph 81 criteria.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐ Transmission Owner	Owns and maintains transmission facilities.

Reliability Functions		
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Reliability and Market Interface Principles	
Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A
WECC	N/A

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Standards Authorization Request Form

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sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards. Please use this form to submit your request to propose a new or a revision to a NERC Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	PRC-025-1 – Generator Relay Loadability		
Date Submitted:	August 25, 2016		
SAR Requester Information for #1			
Name:	Rich Quest		
Organization:	Midwest Reliability Organization		
Telephone:	(651) 855-1704	Email:	rp.quest@midwestreliability.org
SAR Requester Information for #2			
Name:	Jerry Thompson, E.I.T.		
Organization:	Kestrel Power Engineering		
Telephone:	(571) 293-1119	Email:	jerry@kestrelpower.com
SAR Requester Information for #3			
Name:	Joe DePoorter		
Organization:	Madison Gas & Electric		
Telephone:	(608) 252-1599	Email:	JDePoorter@mge.com

Request to propose a new or a revision to a Reliability Standard			
SAR Requester Information for #4			
Name:	Éric Loiselle, ing.		
Organization:	Hydro-Québec TransÉnergie		
Telephone:	(514) 879-4100	Email:	Loiselle.Eric2@hydro.qc.ca
SAR Type (Check as many as applicable)			
☐ New Standard ☒ Revision to Existing Standard		☐ Withdrawal of Existing Standard ☒ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
This SAR proposes revising PRC-025-1 for four specific problems. 1. Prevent instances of non-compliance for conditions where the Generator Owner may be prevented from achieving the margin specified by the standard for dispersed generation resources (DGR). 2. Prevent a lowering of reliability and potential non-compliance where the Generator Owner might apply a non-standard relay element application and undermine the goal of the standard. 3. Prevent a lowering of reliability where the Generator Owner might only apply part of the Table 1 application(s) thereby misapplying the loadability margins to relays for the stated application(s). 4. Prevent a lowering of dependability of protective relays directional toward the transmission system at generating facilities that are remote to the transmission network.
Purpose or Goal (How does this request propose to address the problem described above?):
Consider revising the PRC-025-1 standard through the standards development process to: (1) provide alternative loadability Options for Table 1 specific to DGR; (2) address the inclusion or exclusion of the 50 element (i.e., instantaneous), (3) review Table 1 for proper application where there is more than one application for the available Option(s), and (4) provide alternative or additional Options for Table 1 specific to relay applications that are directional toward the transmission system where the interconnecting transmission line impedance may be a factor in determining the maximum reactive output of the generators and associated relay settings.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
This SAR proposes the need for revising PRC-025-1 for four specific problems. 1. PRC-025-1, Table 1 requires setting the overcurrent relay of a Protection System applied to an asynchronous generating unit or an Element utilized in the aggregation of DGR to a margin greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor. This may result in instances of non-compliance due manufacturer requirements or physical limitations of DGR and may result in an overly conservative relay setting. Consider revising the standard to provide alternative options for setting the overcurrent element of a Protection System applied to an asynchronous generating unit and an Element utilized in the aggregation of DGR. 2. There is potential for Generator Owners to apply a pick up setting of the 50 element (i.e., instantaneous overcurrent) of a Protection System, which is not applicable to the standard, that is lower than the minimum pick up established by the standard for the 51 element (i.e., time delayed overcurrent). The 50 element is generally not used in the generator applications where the 51 element is found in the standard. Consider revising the standard to address the inclusion or exclusion of the 50 element for the various overcurrent applications within Table 1. 3. There is potential for Generator Owners not to apply loadability margins to all load-responsive protective relays in Table 1 of PRC-025-1 under the "Application" column that may affect loadability. For example, the Application column from Table 1 (Options 4, 5, and 6): *"Asynchronous generating unit(s) (including inverter-based installations),* ***or*** *Elements utilized in the aggregation of dispersed power producing resources."* The above clause is separated by an "or" conjunction and may lead the Generator Owner to set one particular application and not the other. This may create a gap in achieving the goal of the standard when loadability margins are not applied to relays on certain Elements. Consider revising the standard to make it clear whether either or both of the listed Elements in the Application column of Options 1-6 must meet the criteria of the particular Option. 4. In the case of remote generating facilities that are electrically weak at its connection to the transmission network, the maximum reactive power required by the specific Table 1 Options is too high to be observed in any recoverable stressed condition. This is due to the system impedance (mainly line impedance) restricting the maximum reactive power output by the generator, no matter the generator characteristics. Lastly, applying the existing Table 1 Options for relay applications directional toward the transmission system results in an overly

SAR Information
conservative relay setting and could require reducing the backup protection coverage in order to comply with the stressed system condition anticipated by the standard.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The PRC-025-1 standard became effective on October 1, 2014 and has a phased implementation of five and seven years (i.e., 2019 or 2021) depending on the scope of work required by the Generator Owner. During the early stages of implementation, the above four problems were revealed by industry. The scope of work will be to consider providing (1) an alternative loadability margin for DGR, (2) revision that includes or excludes 50 element for overcurrent applications, (3) clarification of the application of the Elements in Table 1 of PRC-025-1 for each option that has two applicable Elements separated by an "or" conjunction, and (4) alternative or additional Option(s) (e.g., calculation or method) for determining loadability settings for relays that are directional toward the transmission.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
1. Consider revising the PRC-025-1 standard concerning #1 above through the standards development process to provide a means to determine alternative loadability Options for Table 1 of the standard specific to DRG equipment where there could be a manufacturer requirement or physical equipment limitation. Similar to the provisions already contained in the standard, consider methods that would eliminate the potential for non-compliance and/or a violation of manufacturer specifications. For example: (a) a provision could allow a margin consistent with the manufacturer's requirements or based on the limitation of the equipment; (b) a provision to allow the DRG output to be studied through simulation (e.g., similar to Options 1c and 2c) and the relays to be set with an appropriate margin determined through the standard development process; (c) a provision to exempt equipment with fixed limitations installed prior to the effective date of PRC-025-1 or other justifiable date; and/or (d) any other equally effective and efficient method to accomplish the goal. 2. Consider revising the PRC-025-1 standard concerning #2 above to address the inclusion or exclusion of the 50 element (i.e., instantaneous overcurrent) of a Protection System with or without intentional time delay. Newer techniques in generator protection applications may result in a gap due to non-traditional applications of generator overcurrent relays.

SAR Information
3. Consider revising the PRC-025-1 standard concerning #3 above through the standards development process to bring awareness and clarification whether either or both of the Elements listed in the "Application" column of Table 1, Options 1-6 are to have loadability margins applied to the load-responsive protective relays. 4. Consider revising the PRC-025-1 standard concerning #4 above through the standards development process to provide a means to determine alternative loadability Option(s) for Table 1 of the standard specific to relays directional toward the transmission system. Similar to the provisions already contained in the standard, consider: (a) alternative Options for relay settings where the interconnecting transmission line impedance has a significant impact the maximum reactive output of the generating facility and the associated relay settings, (b) the technical validity of the existing options in the presence of significant transmission line impedance between generation and the network, and/or (c) any other equally effective and efficient method to address the problem of significant line impedance effecting how phase protective relays are set not limit generator loadability while maintaining reliable protection of the BES for all fault conditions.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.

Reliability Functions		
☐	Transmission Planner	Develops a one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the end-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the end-use customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.

Reliability and Market Interface Principles	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
None.	

Related SARs	
SAR ID	Explanation
None.	

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.
MRO	None.
NPCC	None.
RFC	None.
SERC	None.
SPP	None.
WECC	None.

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Summary of Proposed Revisions to the Standard Processes Manual

Appendix 3A to the NERC Rules of Procedure
Section 6.0, Processes for Conducting Field Tests | September 2015

Revisions are proposed to Section 6, *Processes for Conducting Field Tests and Collecting and Analyzing Data*, of the NERC Standard Processes Manual (SPM), Appendix 3A to the NERC Rules of Procedure. Under Section 6.0 of the SPM, field tests may be used to analyze data and validate concepts in the development of Reliability Standards. Changes are proposed to develop a more concise process for conducting field tests, to clarify oversight and authority over the technical aspects of field tests, and to increase coordination across the Standards Committee (SC) and the NERC technical committee overseeing the field test when field tests are conducted.

A redline of the proposed changes is available on the Revisions to the NERC SPM page.

The proposed revisions are posted for a 30-day informal comment period from September 29, 2015 through October 28, 2015. All comments should be submitted through the NERC Standards Balloting and Commenting System (SBS).

Background

In March 2015, the SC endorsed developing draft revisions to the SC Charter and Section 6 of the SPM to develop more concise language and provide NERC's technical committees with additional oversight and authority over the technical aspect of field tests associated with Standards Authorization Requests and standards projects.

NERC staff, along with members of the NERC Operating Committee, Planning Committee, and Critical Infrastructure Protection Committee, worked together to develop the proposed revisions.

Summary of Proposed Revisions

The proposed revisions are summarized as follows:

Section 6.1 is revised to streamline the requirements for field tests to validate concepts that support the development of requirements (current Section 6.1) and field tests of technical concepts in a proposed new or revised Reliability Standard (current Section 6.2). Two new subsections are created:

> Proposed Section 6.1.1 summarizes, in bullet form, the requirements for seeking approval of a field test. Under the proposed revisions, the requesting team must first identify a NERC technical committee to lead the effort to conduct the field test and seek approval from that technical committee to conduct the field test before seeking SC approval.

Proposed Section 6.1.2 provides that the lead NERC technical committee overseeing the field test may stop or modify the field test if it determines that the field test activity poses a reliability risk to the Bulk Electric System (BES). Prior to restarting a stopped field test, the requesting team must receive approval from the lead NERC technical committee and the SC in accordance with proposed Section 6.1.1.

Proposed Section 6.2 clarifies the processes governing communication and coordination for all types of field tests. The proposed revisions clarify the process for seeking, approving, and making notifications with respect to compliance waivers for participating entities unable to comply with currently-enforceable Reliability Standards due to their participation in the field test. Proposed Section 6.2 also contains requirements for keeping the NERC Board of Trustees informed of pending and ongoing field tests, including any requested compliance waivers.

Next Steps

NERC staff will consider all comments received during the comment period and determine next steps.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Processes Manual

VERSION ~~3~~ TBD

Effective: ~~June 26, 2013~~TBD

to ensure the reliability of the bulk power system

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Section 1.0: Introduction

1.1: Authority
This manual is published by the authority of the NERC Board of Trustees. The Board of Trustees, as necessary to maintain NERC's certification as the Electric Reliability Organization ("ERO"), may file the manual with Applicable Governmental Authorities for approval as an ERO document. When approved, the manual is appended to and provides implementation detail in support of the ERO Rules of Procedure Section 300 — Reliability Standards Development.

Capitalized terms not otherwise defined herein, shall have the meaning set forth in the Definitions Used in the Rules of Procedure, Appendix 2 to the Rules of Procedure.

1.2: Scope
The policies and procedures in this manual shall govern the activities of the North American Electric Reliability Corporation ("NERC") related to the development, approval, revision, reaffirmation, and withdrawal of Reliability Standards, Interpretations, Violation Risk Factors ("VRFs"), Violation Severity Levels ("VSLs"), definitions, Variances, and reference documents developed to support standards for the Reliable Operation and planning of the North American Bulk Power Systems.

This manual also addresses the role of the Standards Committee, drafting team and ballot body in the development and approval of Compliance Elements in conjunction with standard development.

1.3: Background
NERC is a nonprofit corporation formed for the purpose of becoming the North American ERO. NERC works with all stakeholder segments of the electric industry, including electricity users, to develop Reliability Standards for the reliability planning and Reliable Operation of the North American Bulk Power Systems. In the United States, the Energy Policy Act of 2005 added Section 215 to the Federal Power Act for the purpose of establishing a framework to make Reliability Standards mandatory for all Bulk Power System owners, operators, and users. Similar authorities are provided by Applicable Governmental Authorities in Canada. NERC was certified as the ERO effective July 2006. *North American Electric Reliability Corp*., 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030 (2007).

1.4: Essential Attributes of NERC's Reliability Standards Processes
NERC's Reliability Standards development processes provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing a proposed Reliability Standard consistent with the attributes necessary for American National Standards Institute ("ANSI") accreditation. The same attributes, as well as transparency, consensus-building, and timeliness, are also required under the ERO Rules of Procedure Section 304.

- ***Open Participation***
  Participation in NERC's Reliability Standards development balloting and approval processes shall be open to all entities materially affected by NERC's Reliability Standards. There shall be no financial barriers to participation in NERC's Reliability Standards balloting and approval processes. Membership in the Registered Ballot Body shall not be conditional upon membership in any organization, nor unreasonably restricted on the basis of technical qualifications or other such requirements.

- ***Balance***
  NERC's Reliability Standards development processes shall not be dominated by any two interest categories, individuals, or organizations and no single interest category, individual, or organization is able to defeat a matter.

  NERC shall use a voting formula that allocates each industry Segment an equal weight in determining the final outcome of any Reliability Standard action. The Reliability Standards development processes shall have a balance of interests. Participants from diverse interest categories shall be encouraged to join the Registered Ballot Body and participate in the balloting process, with a goal of achieving balance between the interest categories. The Registered Ballot Body serves as the consensus body voting to approve each new or proposed Reliability Standard, definition, Variance, and Interpretation.

- ***Coordination and harmonization with other American National Standards activities***
  NERC is committed to resolving any potential conflicts between its Reliability Standards development efforts and existing American National Standards and candidate American National Standards.

- ***Notification of standards development***
  NERC shall publicly distribute a notice to each member of the Registered Ballot Body, and to each stakeholder who indicates a desire to receive such notices, for each action to create, revise, reaffirm, or withdraw a Reliability Standard, definition, or Variance; and for each proposed Interpretation. Notices shall be distributed electronically, with links to the relevant information, and notices shall be posted on NERC's Reliability Standards web page. All notices shall identify a readily available source for further information.

- ***Transparency***
  The process shall be transparent to the public.

- ***Consideration of views and objections***
  Drafting teams shall give prompt consideration to the written views and objections of all participants as set forth herein. Drafting teams shall make an effort to resolve each objection that is related to the topic under review.

- ***Consensus Building***
  The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

- ***Consensus vote***
  NERC shall use its voting process to determine if there is sufficient consensus to approve a proposed Reliability Standard, definition, Variance, or Interpretation. NERC shall form a ballot pool for each Reliability Standard action from interested members of its Registered Ballot Body. Approval of any Reliability Standard action requires:

  - A quorum, which is established by at least 75% of the members of the ballot pool submitting a response excluding unreturned ballots; and
  - A two-thirds majority of the weighted Segment votes cast shall be affirmative. The number of votes cast during all stages of balloting except the final ballot is the sum of affirmative and negative votes with comments, excluding abstentions, non-responses, and negative votes without comments. During the final ballot, the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

- ***Timeliness***
  Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

- ***Metric Policy***
  The International System of units is the preferred units of measurement in NERC Reliability Standard. However, because NERC's Reliability Standards apply in Canada, the United States and portions of Mexico, where applicable, measures are provided in both the metric and English units.

1.5: Ethical Participation

All participants in the NERC Standard development process, including drafting teams, quality reviewers, Standards Committee members and members of the Registered Ballot Body, are obligated to act in an ethical manner in the exercise of all activities conducted pursuant to the terms and conditions of the Standard Processes Manual and the standard development process.

Section 2.0: Elements of a Reliability Standard

2.1: Definition of a Reliability Standard

A Reliability Standard includes a set of Requirements that define specific obligations of owners, operators, and users of the North American Bulk Power Systems. The Requirements shall be material to reliability and measurable. A Reliability Standard is defined as follows:

> "Reliability Standard" means a requirement 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. *See* Appendix 2 to the NERC Rules of Procedure, Definitions Used in the Rules of Procedure.

2.2: Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American Bulk Power Systems.[1] Each Reliability Standard shall enable or support one or more of the reliability principles, thereby ensuring that each Reliability Standard serves a purpose in support of reliability of the North American Bulk Power Systems. Each Reliability Standard shall also be consistent with all of the reliability principles, thereby ensuring that no Reliability Standard undermines reliability through an unintended consequence.

2.3: Market Principles

Recognizing that Bulk Power System reliability and electricity markets are inseparable and mutually interdependent, all Reliability Standards shall be consistent with the market interface principles.[2] Consideration of the market interface principles is intended to ensure that Reliability Standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

2.4: Types of Reliability Requirements

Generally, each Requirement of a Reliability Standard shall identify what Functional Entities shall do, and under what conditions, to achieve a specific reliability objective. Although Reliability Standards all follow this format, several types of Requirements may exist, each with a different approach to measurement.

- **Performance-based Requirements** define a specific reliability objective or outcome achieved by one or more entities that has a direct, observable effect on the reliability of the Bulk Power System, *i.e.* an effect that can be measured using power system data or trends. In its simplest form, a performance-based requirement has four components: *who,*

[1] The intent of the set of NERC Reliability Standards is to deliver an adequate level of reliability. The latest set of reliability principles and the latest set of characteristics associated with an adequate level of reliability are posted on the Reliability Standards Resources web page.

[2] The latest set of market interface principles is posted on the Reliability Standards Resources web page.

under what conditions (if any), shall perform what action, to achieve what particular result or outcome.

- **Risk-based Requirements** define actions by one or more entities that reduce a stated risk to the reliability of the Bulk Power System and can be measured by evaluating a particular product or outcome resulting from the required actions. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the Bulk Power System.*

- **Capability-based Requirements** define capabilities needed by one or more entities to perform reliability functions and can be measured by demonstrating that the capability exists as required. A capability-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the Bulk Power System.*

The body of reliability Requirements collectively provides a defense-in-depth strategy supporting reliability of the Bulk Power System.

2.5: Elements of a Reliability Standard

A Reliability Standard includes several components designed to work collectively to identify what entities must do to meet their reliability-related obligations as an owner, operator or user of the Bulk Power System.

The components of a Reliability Standard may include the following:

Title: A brief, descriptive phrase identifying the topic of the Reliability Standard.

Number: A unique identification number assigned in accordance with a published classification system to facilitate tracking and reference to the Reliability Standards.[3]

Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard.

Applicability: Identifies which entities are assigned reliability requirements. The specific Functional Entities and Facilities to which the Reliability Standard applies.

Effective Dates: Identification of the date or pre-conditions determining when each Requirement becomes effective in each jurisdiction.

Requirement: An explicit statement that identifies the Functional Entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each Requirement shall be a statement for which compliance is mandatory.

[3] Reliability Standards shall be numbered in accordance with the NERC Standards Numbering Convention as provide on the Reliability Standards Resources web page.

Compliance Elements: Elements to aid in the administration of ERO compliance monitoring and enforcement responsibilities.[4]

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

- ***Violation Risk Factors and Violation Severity Levels:*** Violation risk factors (VRFs) and violation severity levels (VSLs) are used as factors when determining the size of a penalty or sanction associated with the violation of a requirement in an approved reliability standard.[5] Each requirement in each reliability standard has an associated VRF and a set of VSLs. VRFs and VSLs are developed by the drafting team, working with NERC Staff, at the same time as the associated reliability standard, but are not part of the reliability standard. The Board of Trustees is responsible for approving VRFs and VSLs.

  - ***Violation Risk Factors***
    VRFs identify the potential reliability significance of noncompliance with each requirement. Each requirement is assigned a VRF in accordance with the latest approved set of VRF criteria.[6]

  - ***Violation Severity Levels***
    VSLs define the degree to which compliance with a requirement was not achieved. Each requirement shall have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs. Each requirement is assigned one or more VSLs in accordance with the latest approved set of VSL criteria.[7]

Version History: The version history is provided for informational purposes and lists information regarding prior versions of Reliability Standards.

Variance: A Requirement (to be applied in the place of the continent-wide Requirement) that is applicable to a specific geographic area or to a specific set of Registered Entities.

Compliance Enforcement Authority: The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated Reliability Standard. The Compliance Enforcement Authority will be NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

***Application guidelines*:** Guidelines to support the implementation of the associated Reliability Standard.

***Procedures*:** Procedures to support implementation of the associated Reliability Standard.

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[4] It is the responsibility of the ERO staff to develop compliance tools for each standard; these tools are not part of the standard but are referenced in this manual because the preferred approach to developing these tools is to use a transparent process that leverages the technical and practical expertise of the drafting team and ballot pool..

[5] The *Sanction Guidelines of the North American Electric Reliability Corporation* identifies the factors used to determine a penalty or sanction for violation of reliability standard and is posted on the NERC Web Site.

[6] The latest set of approved VRF Criteria is posted on the Reliability Standards Resources Web Page.

[7] The latest set of approved VSL Criteria is posted on the Reliability Standards Resources Web Page.

The only mandatory and enforceable components of a Reliability Standard are the: (1) applicability, (2) Requirements, and the (3) effective dates. The additional components are included in the Reliability Standard for informational purposes, to establish the relevant scope and technical paradigm, and to provide guidance to Functional Entities concerning how compliance will be assessed by the Compliance Enforcement Authority.

Section 3.0: Reliability Standards Program Organization

3.1: Board of Trustees

The NERC Board of Trustees shall consider for adoption Reliability Standards, definitions, Variances and Interpretations and associated implementation plans that have been processed according to the processes identified in this manual. Once the Board adopts a Reliability Standard, definition, Variance or Interpretation, the Board shall direct NERC Staff to file the document(s) for approval with Applicable Governmental Authorities.

3.2: Registered Ballot Body

The Registered Ballot Body comprises all entities or individuals that qualify for one of the Segments approved by the Board of Trustees[8], and are registered with NERC as potential ballot participants in the voting on Reliability Standards. Each member of the Registered Ballot Body is eligible to join the ballot pool for each Reliability Standard action.

3.3: Ballot Pool

Each Reliability Standard action has its own ballot pool formed of interested members of the Registered Ballot Body. The ballot pool comprises those members of the Registered Ballot Body that respond to a pre-ballot request to participate in that particular Reliability Standard action. The ballot pool votes on each Reliability Standards action. The ballot pool remains in place until all balloting related to that Reliability Standard action has been completed.

3.4: Standards Committee

The Standards Committee serves at the pleasure and direction of the NERC Board of Trustees, and the Board approves the Standards Committee's Charter.[9] Standards Committee members are elected by their respective Segment's stakeholders. The Standards Committee consists of two members of each of the Segments in the Registered Ballot Body.[10] A member of the NERC Reliability Standards Staff shall serve as the non-voting secretary to the Standards Committee.

The Standards Committee is responsible for managing the Reliability Standards processes for development of Reliability Standards, definitions, Variances and Interpretations in accordance with this manual. The responsibilities of the Standards Committee are defined in detail in the Standards Committee's Charter. The Standards Committee is responsible for ensuring that the Reliability Standards, definitions, Variances and Interpretations developed by drafting teams are developed in accordance with the processes in this manual and meet NERC's benchmarks for Reliability Standards as well as criteria for governmental approval.[11]

The Standards Committee has the right to remand work to a drafting team, to reject the work of a drafting team, or to accept the work of a drafting team. The Standards Committee may disband a drafting team if it determines (a) that the drafting team is not producing a standard in a timely manner; (b) the drafting team

[8] The industry Segment qualifications are described in the Development of the Registered Ballot Body and Segment Qualification Guidelines document posted on the Reliability Standards Resources web page and are included in Appendix 3D of the NERC Rules of Procedure.

[9] The Standards Committee Charter is posted on the Reliability Standards Resources web page.

[10] In addition to balanced Segment representation, the Standards Committee shall also have representation that is balanced among countries based on Net Energy for Load ("NEL"). As needed, the Board of Trustees may approve special procedures for the balancing of representation among countries represented within NERC.

[11] The Ten Benchmarks of an Excellent Reliability Standard and FERC's Criteria for Approving Reliability Standards are posted on the Reliability Standards Resources web page.

is not able to produce a standard that will achieve industry consensus; (c) the drafting team has not addressed the scope of the SAR; or (d) the drafting team has failed to fully address a regulatory directive or otherwise provided a responsive or equally efficient and effective alternative. The Standards Committee may direct a drafting team to revise its work to follow the processes in this manual or to meet the criteria for NERC's benchmarks for Reliability Standards, or to meet the criteria for governmental approval; however, the Standards Committee shall not direct a drafting team to change the technical content of a draft Reliability Standard.

The Standards Committee shall meet at regularly scheduled intervals (either in person, or by other means). All Standards Committee meetings are open to all interested parties.

3.5: NERC Reliability Standards Staff

The NERC Reliability Standards Staff, led by the Director of Standards, is responsible for administering NERC's Reliability Standards processes in accordance with this manual. The NERC Reliability Standards Staff provides support to the Standards Committee in managing the Reliability Standards processes and in supporting the work of all drafting teams. The NERC Reliability Standards Staff works to ensure the integrity of the Reliability Standards processes and consistency of quality and completeness of the Reliability Standards. The NERC Reliability Standards Staff facilitates all steps in the development of Reliability Standards, definitions, Variances, Interpretations and associated implementation plans.

The NERC Reliability Standards Staff is responsible for presenting Reliability Standards, definitions, Variances, and Interpretations to the NERC Board of Trustees for adoption. When presenting Reliability Standards-related documents to the NERC Board of Trustees for adoption or approval, the NERC Reliability Standards Staff shall report the results of the associated stakeholder ballot, including identification of unresolved stakeholder objections and an assessment of the document's practicality and enforceability.

3.6: Drafting Teams

The Standards Committee shall appoint industry experts to drafting teams to work with stakeholders in developing and refining Standard Authorization Requests ("SARs"), Reliability Standards, definitions, and Variances. The NERC Reliability Standards Staff shall appoint drafting teams that develop Interpretations. The NERC Reliability Standards Staff shall provide, or solicit from the industry, essential support for each of the drafting teams in the form of technical writers, legal, compliance, and rigorous and highly trained project management and facilitation support personnel.

Each drafting team may consist of a group of technical, legal, and compliance experts that work cooperatively with the support of the NERC Reliability Standards Staff.[12] The technical experts provide the subject matter expertise and guide the development of the technical aspects of the Reliability Standard, assisted by technical writers, legal and compliance experts. The technical experts maintain authority over the technical details of the Reliability Standard. Each drafting team appointed to develop a Reliability Standard is responsible for following the processes identified in this manual as well as procedures developed by the Standards Committee from the inception of the assigned project through the final acceptance of that project by Applicable Governmental Authorities.

Collectively, each drafting team:

- Drafts proposed language for the Reliability Standards, definitions, Variances, and/or Interpretations and associated implementation plans.

[12] The detailed responsibilities of drafting teams are outlined in the Drafting Team Guidelines, which is posted on the Reliability Standards Resources web page.

- Develops and refines technical documents that aid in the understanding of Reliability Standards.
- Works collaboratively with NERC Compliance Monitoring and Enforcement Staff to develop Reliability Standard Audit Worksheets ("RSAWs") at the same time Reliability Standards are developed.
- Provides assistance to NERC Staff in the development of Compliance Elements of proposed Reliability Standards.
- Solicits, considers, and responds to comments related to the specific Reliability Standards development project.
- Participates in industry forums to help build consensus on the draft Reliability Standards, definitions, Variances, and/or Interpretations and associated implementation plans.
- Assists in developing the documentation used to obtain governmental approval of the Reliability Standards, definitions, Variances, and/or Interpretations and associated implementation plans.

All drafting teams report to the Standards Committee.

3.7: Governmental Authorities

The Federal Energy Regulatory Commission ("FERC") in the United States of America, and where permissible by statute or regulation, the provincial government of each of the eight Canadian Provinces (Manitoba, Nova Scotia, Saskatchewan, Alberta, Ontario, British Columbia, New Brunswick and Quebec) and the National Energy Board of Canada have the authority to approve each new, revised or withdrawn Reliability Standard, definition, Variance, VRF, VSL and Interpretation following adoption or approval by the NERC Board of Trustees.

3.8: Committees, Subcommittees, Working Groups, and Task Forces

NERC's technical committees, subcommittees, working groups, and task forces provide technical research and analysis used to justify the development of new Reliability Standards and provide guidance, when requested by the Standards Committee, in overseeing field tests or collection and analysis of data. The technical committees, subcommittees, working groups, and task forces provide feedback to drafting teams during both informal and formal comment periods.

The Standards Committee may request that a NERC technical committee or other group prepare a Technical document to support development of a proposed Reliability Standard.

The technical committees, subcommittees, working groups, and task forces share their observations regarding the need for new or modified Reliability Standards or Requirements with the NERC Reliability Standards Staff for use in identifying the need for new Reliability Standards projects for the three-year *Reliability Standards Development Plan*.

3.9: Compliance and Certification Committee

The Compliance and Certification Committee is responsible for monitoring NERC's compliance with its Reliability Standards processes and procedures and for monitoring NERC's compliance with the Rules of Procedure regarding the development of new or revised Reliability Standards, definitions, Variances, and Interpretations. The Compliance and Certification Committee may assist in verifying that each proposed Reliability Standard is enforceable as written before the Reliability Standard is posted for formal stakeholder comment and balloting.

3.10: Compliance Monitoring and Enforcement Program

As applicable, the NERC Compliance Monitoring and Enforcement Program Staff manages and enforces compliance with approved Reliability Standards. Compliance Monitoring and Enforcement Staff are responsible for the development of select compliance tools. The drafting team and the Compliance Monitoring and Enforcement Program Staff shall work together during the Reliability Standard development process to ensure an accurate and consistent understanding of the Requirements and their intent, and to ensure that applicable compliance tools accurately reflect that intent. The goal of this collaboration is to ensure that application of the Reliability Standards in the Compliance Monitoring and Enforcement Program by NERC and the Regional Entities is consistent.

The Compliance Monitoring and Enforcement Program is encouraged to share its observations regarding the need for new or modified Requirements with the NERC Reliability Standards Staff for use in identifying the need for new Reliability Standards projects.

3.11: North American Energy Standards Board ("NAESB")

While NERC has responsibility for developing Reliability Standards to support reliability, NAESB has responsibility for developing business practices and coordination between reliability and business practices as needed. NERC and NAESB developed and approved a procedure[13] to guide the development of Reliability Standards and business practices where the reliability and business practice components are intricately entwined within a proposed Reliability Standard.

[13] The NERC NAESB Template Procedure for Joint Standards Development and Coordination is posted on the Reliability Standards Resources web page.

Section 4.0: Process for Developing, Modifying, Withdrawing or Retiring a Reliability Standard

There are several steps to the development, modification, withdrawal or retirement of a Reliability Standard.[14]

The development of the *Reliability Standards Development Plan* is the appropriate forum for reaching agreement on whether there is a need for a Reliability Standard and the scope of a proposed Reliability Standard. A typical process for a project identified in the *Reliability Standards Development Plan* that involves a revision to an existing Reliability Standard is shown below. Note that most projects do not include a field test.

[14] The process described is also applicable to projects used to propose a new or modified definition or Variance or to propose retirement of a definition or Variance.

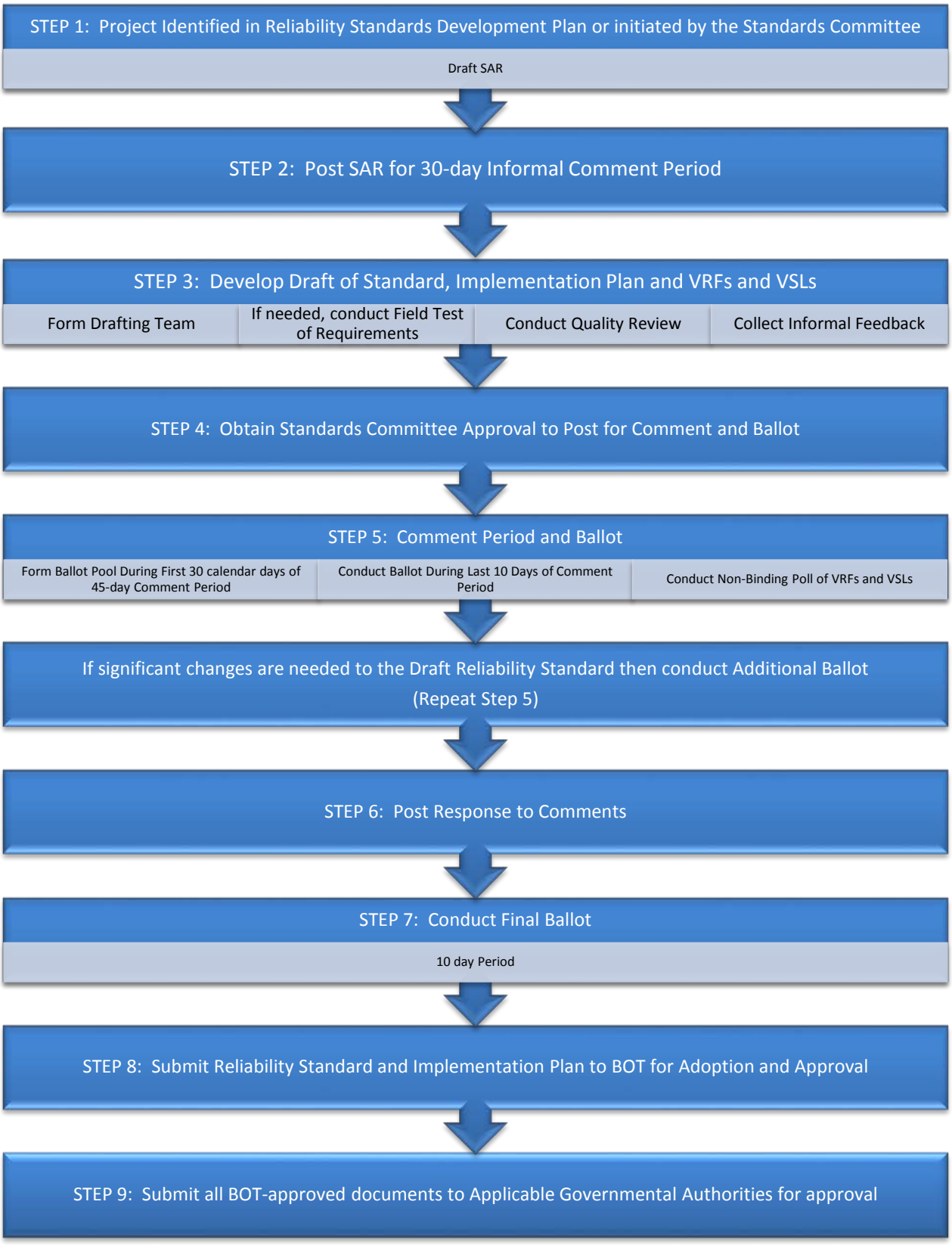


FIGURE 1: Process for Developing or Modifying a Reliability Standard

4.1: Posting and Collecting Information on SARs

Standard Authorization Request

A Standard Authorization Request ("SAR") is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified Reliability Standards or definitions or the benefit of retiring one or more approved Reliability Standards. Any entity or individual, including NERC committees or subgroups and NERC Staff, may propose the development of a new or modified Reliability Standard, or may propose the retirement of a Reliability Standard (in whole or in part), by submitting a completed SAR[15] to the NERC Reliability Standards Staff. The Standards Committee has the authority to approve the posting of all SARs for projects that propose (i) developing a new or modified Reliability Standard or definition or (ii) propose retirement of an existing Reliability Standard (or elements thereof).

The NERC Reliability Standards Staff sponsors an open solicitation period each year seeking ideas for new Reliability Standards projects (using *Reliability Standards Suggestions and Comments forms*). The open solicitation period is held in conjunction with the annual revision to the *Reliability Standards Development Plan*. While the Standards Committee prefers that ideas for new projects be submitted during this annual solicitation period through submittal of a *Reliability Standards Suggestions and Comments Form*,[16] a SAR proposing a specific project may be submitted to the NERC Reliability Standards Staff at any time.

Each SAR that proposes a "new" or substantially revised Reliability Standard or definition should be accompanied by a technical justification that includes, as a minimum, a discussion of the reliability-related benefits and costs of developing the new Reliability Standard or definition, and a technical foundation document (*e.g.*, research paper) to guide the development of the Reliability Standard or definition. The technical document should address the engineering, planning and operational basis for the proposed Reliability Standard or definition, as well as any alternative approaches considered during SAR development.

The NERC Reliability Standards Staff shall review each SAR and work with the submitter to verify that all required information has been provided. All properly completed SARs shall be submitted to the Standards Committee for action at the next regularly scheduled Standards Committee meeting.

When presented with a SAR, the Standards Committee shall determine if the SAR is sufficiently complete to guide Reliability Standard development and whether the SAR is consistent with this manual. The Standards Committee shall take one of the following actions:

- Accept the SAR.
- Remand the SAR back to the requestor or to NERC Reliability Standards Staff for additional work.
- Reject the SAR. The Standards Committee may reject a SAR for good cause. If the Standards Committee rejects a SAR, it shall provide a written explanation for rejection to the sponsor within ten days of the rejection decision.
- Delay action on the SAR pending one of the following: (i) development of a technical justification for the proposed project; or (ii) consultation with another NERC Committee to determine if there is another approach to addressing the issue raised in the SAR.

If the Standards Committee is presented with a SAR that proposes developing a new Reliability Standard or definition but does not have a technical justification upon which the Reliability Standard or definition can be developed, the Standards Committee shall direct the NERC Reliability Standards Staff to post the

[15] The SAR form can be downloaded from the Reliability Standards Resources web page.
[16] The *Reliability Standards Suggestions and Comments Form* can be downloaded from the Reliability Standards Resources web page.

SAR for a 30-day comment period solely to collect stakeholder feedback on the scope of technical foundation, if any, needed to support the proposed project. If a technical foundation is determined to be necessary, the Standards Committee shall solicit assistance from NERC's technical committees or other industry experts to provide that foundation before authorizing development of the associated Reliability Standard or definition.

During the SAR comment process, the drafting team may become aware of potential regional Variances related to the proposed Reliability Standard. To the extent possible, any regional Variances or exceptions should be made a part of the SAR so that if the SAR is authorized, such variations shall be made a part of the draft new or revised Reliability Standard.

If the Standards Committee accepts a SAR, the project shall be added to the list of approved projects. The Standards Committee shall assign a priority to the project, relative to all other projects under development, and those projects already identified in the *Reliability Standards Development Plan* that are already approved for development.

The Standards Committee shall work with the NERC Reliability Standards Staff to coordinate the posting of SARs for new projects, giving consideration to each project's priority.

4.2: SAR Posting

When the Standards Committee determines it is ready to initiate a new project, the Standards Committee shall direct NERC Staff to post the project's SAR in accordance with the following:

- For SARs that are limited to addressing regulatory directives, or revisions to Reliability Standards that have had some vetting in the industry, authorize posting the SAR for a 30-day informal comment period with no requirement to provide a formal response to the comments received.
- For SARs that address the development of new projects or Reliability Standards, authorize posting the SAR for a 30-day formal comment period.

If a SAR for a new Reliability Standard is posted for a formal comment period, the Standards Committee shall appoint a drafting team to work with the NERC Staff coordinator to give prompt consideration of the written views and objections of all participants. The Standards Committee may use a public nomination process to populate the Reliability Standard drafting team, or may use another method that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. In some situations, an *ad hoc* team may already be in place with the requisite expertise, competencies, and diversity of views that are necessary to refine the SAR and develop the Reliability Standard, and additional members may not be needed. The drafting team shall address all comments submitted, which may be in the form of a summary response addressing each of the issues raised in comments received, during the public posting period. An effort to resolve all expressed objections shall be made, and each objector shall be advised of the disposition of the objection and the reasons therefore. If the drafting team concludes that there is not sufficient stakeholder support to continue to refine the SAR, the team may recommend that the Standards Committee direct curtailment of work on the SAR.

While there is no established limit on the number of times a SAR may be posted for comment, the Standards Committee retains the right to reverse its prior decision and reject a SAR if it believes continued revisions are not productive. The Standards Committee shall notify the sponsor in writing of the rejection within 10 calendar days.

If stakeholders indicate support for the project proposed with the SAR, the drafting team shall present its work to the Standards Committee with a request that the Standards Committee authorize development of the associated Reliability Standard.

The Standards Committee, once again considering the public comments received and their resolution, may then take one of the following actions:

- Authorize drafting the proposed Reliability Standard or revisions to a Reliability Standard.
- Reject the SAR with a written explanation to the sponsor and post that explanation.

4.3: Form Drafting Team

When the Standards Committee is ready to have a drafting team begin work on developing a new or revised Reliability Standard, the Standards Committee shall appoint a drafting team, if one was not already appointed to develop the SAR. If the Standards Committee appointed a drafting team to refine the SAR, the same drafting team shall work to develop the associated Reliability Standard.

If no drafting team is in place, then the Standards Committee may use a public nomination process to populate the Reliability Standard drafting team, or may use another method that results in a team that collectively has the necessary technical expertise, diversity of views and work process skills to accomplish the objectives of the project on a timely basis. In some situations, an ad hoc team may already be in place with the requisite expertise, competencies, and diversity of views that are necessary to develop the Reliability Standard, and additional members may not be needed.

The NERC Reliability Standards Staff shall provide one or more members as needed to support the team with facilitation, project management, compliance, legal, regulatory and technical writing expertise and shall provide administrative support to the team, guiding the team through the steps in completing its project. In developing the Reliability Standard, the individuals provided by the NERC Reliability Standards Staff serve as advisors to the drafting team and do not have voting rights but share accountability along with the drafting team members assigned by the Standards Committee for timely delivery of a final draft Reliability Standard that meets the quality attributes identified in NERC's Benchmarks for Excellent Standards. The drafting team members assigned by the Standards Committee shall have final authority over the technical details of the Reliability Standard, while the technical writer shall provide assistance to the drafting team in assuring that the final draft of the Reliability Standard meets the quality attributes identified in NERC's Benchmarks for Excellent Standards.

Once it is appointed by the Standards Committee, the Reliability Standard drafting team is responsible for making recommendations to the Standards Committee regarding the remaining steps in the Reliability Standards process. Consistent with the need to provide for timely standards development, the Standards Committee may decide a project is so large that it should be subdivided and either assigned to more than one drafting team or assigned to a single drafting team with clear direction on completing the project in specified phases. The normally expected timeframes for standards development within the context of this manual are applicable to individual standards and not to projects containing multiple standards. Alternatively, a single drafting team may address the entire project with a commensurate increase in the expected duration of the development work. If a SAR is subdivided and assigned to more than one drafting team, each drafting team will have a clearly defined portion of the work such that there are no overlaps and no gaps in the work to be accomplished.

The Standards Committee may supplement the membership of a Reliability Standard drafting team or provide for additional advisors, as appropriate, to ensure the necessary competencies and diversity of views are maintained throughout the Reliability Standard development effort.

4.4: Develop Preliminary Draft of Reliability Standard, Implementation Plan and VRFs and VSLs

4.4.1: Project Schedule

When a drafting team begins its work, either in refining a SAR or in developing or revising a proposed Reliability Standard, the drafting team shall develop a project schedule which shall be approved by the Standards Committee. The drafting team shall report progress to the Standards Committee, against the initial project schedule and any revised schedule as requested by the Standards Committee. Where project milestones cannot be completed on a timely basis, modifications to the project schedule must be presented to the Standards Committee for consideration along with proposed steps to minimize unplanned project delays.

4.4.2: Draft Reliability Standard

The team shall develop a Reliability Standard that is within the scope of the associated SAR that includes all required elements as described earlier in this manual with a goal of meeting the quality attributes identified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval. The team shall document its justification for the Requirements in its proposed Reliability Standard by explaining how each meets these criteria. The standard drafting team shall document its justification for selecting each reference by explaining how each Requirement fits the category chosen.

4.4.3: Implementation Plan

As a drafting team drafts its proposed revisions to a Reliability Standard, that team is also required to develop an implementation plan to identify any factors for consideration when approving the proposed effective date or dates for the associated Reliability Standard or Standards. As a minimum, the implementation plan shall include the following:

- The proposed effective date (the date entities shall be compliant) for the Requirements.
- Identification of any new or modified definitions that are proposed for approval with the associated Reliability Standard.
- Whether there are any prerequisite actions that need to be accomplished before entities are held responsible for compliance with one or more of the Requirements.
- Whether approval of the proposed Reliability Standard will necessitate any conforming changes to any already approved Reliability Standards – and identification of those Reliability Standards and Requirements.
- The Functional Entities that will be required to comply with one or more Requirements in the proposed Reliability Standard.

A single implementation plan may be used for more than one Reliability Standard. The implementation plan is posted with the associated Reliability Standard or Standards during the 45 (calendar) day formal comment period and is balloted with the associated Reliability Standard.

4.4.4: Violation Risk Factors and Violation Severity Levels

The drafting team shall work with NERC Staff in developing a set of VRFs and VSLs that meet the latest criteria established by NERC and Applicable Governmental Authorities. The drafting team shall document its justification for selecting each VRF and for setting each set of proposed VSLs by explaining how its proposed VRFs and VSLs meet these criteria. NERC Staff is responsible for ensuring that the VRFs and VSLs proposed for stakeholder review meet these criteria.

Before the drafting team has finalized its Reliability Standard, implementation plan, and VRFs and VSLs, the team should seek stakeholder feedback on its preliminary draft documents.

4.5: Informal Feedback[17]

Drafting teams may use a variety of methods to collect informal stakeholder feedback on preliminary drafts of its documents, including the use of informal comment periods,[18] webinars, industry meetings, workshops, or other mechanisms. Information gathered from informal comment forms shall be publicly posted. While drafting teams are not required to provide a written response to each individual comment received, drafting teams are encouraged, where possible, to post a summary response that identifies how it used comments submitted by stakeholders. Drafting teams are encouraged, where possible, to reach out directly to individual stakeholders in order to facilitate resolution of identified stakeholder concerns. The intent is to gather stakeholder feedback on a "working document" before the document reaches the point where it is considered the "final draft."

4.6: Conduct Quality Review

The NERC Reliability Standards Staff shall coordinate a quality review of the Reliability Standard, implementation plan, and VRFs and VSLs in parallel with the development of the Reliability Standard and implementation plan, to assess whether the documents are within the scope of the associated SAR, whether the Reliability Standard is clear and enforceable as written, and whether the Reliability Standard meets the criteria specified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval of Reliability Standards. The drafting team shall consider the results of the quality review, decide upon appropriate changes, and recommend to the Standards Committee whether the documents are ready for formal posting and balloting.

The Standards Committee shall authorize posting the proposed Reliability Standard, and implementation plan for a formal comment period and ballot and the VRFs and VSLs for a non-binding poll as soon as the work flow will accommodate.

If the Standards Committee finds that any of the documents do not meet the specified criteria, the Standards Committee shall remand the documents to the drafting team for additional work.

If the Reliability Standard is outside the scope of the associated SAR, the drafting team shall be directed to either revise the Reliability Standard so that it is within the approved scope, or submit a request to expand the scope of the approved SAR. If the Reliability Standard is not clear and enforceable as written, or if the Reliability Standard does not meet the specified criteria, the Reliability Standard shall be returned to the drafting team by the Standards Committee with specific identification of any Requirement that is deemed to be unclear or unenforceable as written.

4.7: Conduct Formal Comment Period and Ballot

Proposed new or modified Reliability Standards require a formal comment period where the new or modified Reliability Standard, implementation plan and associated VRFs and VSLs or the proposal to retire a Reliability Standard, implementation plan and associated VRFs and VSLs are posted.

The formal comment period shall be at least 45-days long. Formation of the ballot pool and Ballot of the Reliability Standard take place during this formal 45-day comment period. The intent of the formal comment period(s) is to solicit very specific feedback on the final draft of the Reliability Standard, implementation plan and VRFs and VSLs.

[17] While this discussion focuses on collecting stakeholder feedback on proposed Reliability Standards and implementation plans, the same process is used to collect stakeholder feedback on proposed new or modified Interpretations, definitions and Variances.

[18] The term "informal comment period" refers to a comment period conducted outside of the ballot process and where there is no requirement for a drafting team to respond in writing to submitted comments.

Comments in written form may be submitted on a draft Reliability Standard by any interested stakeholder, including NERC Staff, FERC Staff, and other interested governmental authorities. If stakeholders disagree with some aspect of the proposed set of products, comments provided should explain the reasons for such disagreement and, where possible, suggest specific language that would make the product acceptable to the stakeholder.

4.8: Form Ballot Pool

The NERC Reliability Standards Staff shall establish a ballot pool during the first 30 calendar days of the 45-day formal comment period. The NERC Reliability Standards Staff shall post the proposed Reliability Standard, along with its implementation plan, VRFs and VSLs and shall send a notice to every entity in the Registered Ballot Body to provide notice that there is a new or revised Reliability Standard proposed for approval and to solicit participants for the associated ballot pool. All members of the Registered Ballot Body are eligible to join each ballot pool to vote on a new or revised Reliability Standard and its implementation plan and to participate in the non-binding poll of the associated VRFs and VSLs.

Any member of the Registered Ballot Body may join or withdraw from the ballot pool until the ballot window opens. No Registered Ballot Body member may join or withdraw from the ballot pool once the first ballot starts through the point in time where balloting for that Reliability Standard action has ended. The Director of Standards may authorize deviations from this rule for extraordinary circumstances such as the death, retirement, or disability of a ballot pool member that would prevent an entity that had a member in the ballot pool from eligibility to cast a vote during the ballot window. Any approved deviation shall be documented and noted to the Standards Committee.

4.9: Conduct Ballot and Non-binding Poll of VRFs and VSLs[19]

The NERC Reliability Standards Staff shall announce the opening of the Ballot window and the non-binding poll of VRFs and VSLs. The Ballot window and non-binding poll of VRFs and VSLs shall take place during the last 10 calendar days of the 45-day formal comment period and for the Final Ballot shall be no less than 10 calendar days. If the last day of the ballot window falls on a Saturday or Sunday, the period does not end until the next business day.[20]

The ballot and non-binding poll shall be conducted electronically. The voting window shall be for a period of 10 calendar days but shall be extended, if needed, until a quorum is achieved. During a ballot window, NERC shall not sponsor or facilitate public discussion of the Reliability Standard action under ballot.

There is no requirement to conduct a new non-binding poll of the revised VRFs and VSLs if no changes were made to the associated standard, however if the requirements are modified and conforming changes are made to the associated VRFs and VSLs, another non-binding poll of the revised VRFs and VSLs shall be conducted.

[19] While RSAWs are not part of the Reliability Standard, they are developed through collaboration of the SDT and NERC Compliance Staff. A non-binding poll, similar to what is done for VRFs and VSLs may be conducted for the RSAW developed through this process to gauge industry support for the companion RSAW to be provided for informational purposes to the NERC Board of Trustees.

[20] Closing dates may be extended as deemed appropriate by NERC Staff.

4.10: Criteria for Ballot Pool Approval

Ballot pool approval of a Reliability Standard requires:

A quorum, which is established by at least 75% of the members of the ballot pool submitting a response; and

A two-thirds majority of the weighted Segment votes cast shall be affirmative. The number of votes cast is the sum of affirmative votes and negative votes with comments. This calculation of votes for the purpose of determining consensus excludes (i) abstentions, (ii) non-responses, and (iii) negative votes without comments.

The following process[21] is used to determine if there are sufficient affirmative votes.

- For each Segment with ten or more voters, the following process shall be used: The number of affirmative votes cast shall be divided by the sum of affirmative and negative votes with comments cast to determine the fractional affirmative vote for that Segment. Abstentions, non-responses, and negative votes without comments shall not be counted for the purposes of determining the fractional affirmative vote for a Segment.
- For each Segment with less than ten voters, the vote weight of that Segment shall be proportionally reduced. Each voter within that Segment voting affirmative or negative with comments shall receive a weight of 10% of the Segment vote.
- The sum of the fractional affirmative votes from all Segments divided by the number of Segments voting[22] shall be used to determine if a two-thirds majority has been achieved. (A Segment shall be considered as "voting" if any member of the Segment in the ballot pool casts either an affirmative vote or a negative vote with comments.)
- A Reliability Standard shall be approved if the sum of fractional affirmative votes from all Segments divided by the number of voting Segments is at least two thirds.

4.11: Voting Positions

Each member of the ballot pool may **only** vote one of the following positions on the Ballot and Additional Ballot(s):

- Affirmative;
- Affirmative, with comment;
- Negative with comments;
- Abstain.

Given that there is no formal comment period concurrent with the Final Ballot, each member of the ballot pool may **only** vote one of the following positions on the Final Ballot:

- Affirmative;
- Negative;[23]
- Abstain.

[21] Examples of weighted segment voting calculation are posted on the Reliability Standards Resources web page.

[22] When less than ten entities vote in a Segment, the total weight for that Segment shall be determined as one tenth per entity voting, up to ten.

[23] The Final Ballot is used to confirm consensus achieved during the Formal Comment and Ballot stage. Ballot Pool members voting negative on the Final Ballot will be deemed to have expressed the reason for their negative ballot in their own comments or the comments of others during prior Formal Comment periods.

4.12: Consideration of Comments
If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot.

There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot.

4.13: Additional Ballots
A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted.

However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an Additional Ballot will be conducted.

4.14: **Conduct Final Ballot**
When the drafting team has reached a point where it has made a good faith effort at resolving applicable objections and is not making any substantive changes from the previous ballot, the team shall conduct a "Final Ballot." A non-substantive revision is a revision that does not change the scope, applicability, or intent of any Requirement and includes but is not limited to things such as correcting the numbering of a Requirement, correcting the spelling of a word, adding an obviously missing word, or rephrasing a Requirement for improved clarity. Where there is a question as to whether a proposed modification is "substantive," the Standards Committee shall make the final determination.

In the Final Ballot, members of the ballot pool shall again be presented the proposed Reliability Standard along with the reasons for negative votes from the previous ballot, the responses of the drafting team to those concerns, and any resolution of the differences.

All members of the ballot pool shall be permitted to reconsider and change their vote from the prior ballot. Members of the ballot pool who did not respond to the prior ballot shall be permitted to vote in the Final Ballot. In the Final Ballot, votes shall be counted by exception only — members on the Final Ballot may indicate a revision to their original vote; otherwise their vote shall remain the same as in their prior ballot.

4.15: Final Ballot Results
There are no limits to the number of public comment periods and ballots that can be conducted to result in a Reliability Standard or interpretation that is clear and enforceable, and achieves a quorum and sufficient affirmative votes for approval. The Standards Committee has the authority to conclude this process for a particular Reliability Standards action if it becomes obvious that the drafting team cannot develop a Reliability Standard that is within the scope of the associated SAR, is sufficiently clear to be enforceable, and achieves the requisite weighted Segment approval percentage.

The NERC Reliability Standards Staff shall post the final outcome of the ballot process. If the Reliability Standard is rejected, the Standards Committee may decide whether to end all further work on the proposed standard, return the project to informal development, or continue holding ballots to attempt to reach

consensus on the proposed standard. If the Reliability Standard is approved, the Reliability Standard shall be posted and presented to the Board of Trustees by NERC management for adoption and subsequently filed with Applicable Governmental Authorities for approval.

4.16: Board of Trustees Adoption of Reliability Standards, Implementation Plan and VRFs and VSLs

If a Reliability Standard and its associated implementation plan are approved by its ballot pool, the Board of Trustees shall consider adoption of that Reliability Standard and its associated implementation plan and shall direct the standard to be filed with Applicable Governmental Authorities for approval. In making its decision, the Board shall consider the results of the balloting and unresolved dissenting opinions. The Board shall adopt or reject a Reliability Standard and its implementation plan, but shall not modify a proposed Reliability Standard. If the Board chooses not to adopt a Reliability Standard, it shall provide its reasons for not doing so.

The board shall consider approval of the VRFs and VSLs associated with a reliability standard. In making its determination, the board shall consider the following:

- The Standards Committee shall present the results of the non-binding poll conducted and a summary of industry comments received on the final posting of the proposed VRFs and VSLs.
- NERC Staff shall present a set of recommended VRFs and VSLs that considers the views of the standard drafting team, stakeholder comments received on the draft VRFs and VSLs during the posting for comment process, the non-binding poll results, appropriate governmental agency rules and directives, and VRF and VSL assignments for other Reliability Standards to ensure consistency and relevance across the entire spectrum of Reliability Standards.

4.17: Compliance

For a Reliability Standard to be enforceable, it shall be approved by its ballot pool, adopted by the NERC Board of Trustees, and approved by Applicable Governmental Authorities, unless otherwise approved by the NERC Board of Trustees pursuant to the NERC Rules of Procedure (*e.g*, Section 321) and approved by Applicable Governmental Authorities. Once a Reliability Standard is approved or otherwise made mandatory by Applicable Governmental Authorities, all persons and organizations subject to jurisdiction of the ERO will be required to comply with the Reliability Standard in accordance with applicable statutes, regulations, and agreements.

4.18: Withdrawal of a Reliability Standard, Interpretation, or Definition

The term "withdrawal" as used herein, refers to the discontinuation of a Reliability Standard, Interpretation, Variance or definition that has been approved by the Board of Trustees and (1) has not been filed with Applicable Governmental Authorities, or (2) has been filed with, but not yet approved by, Applicable Governmental Authorities. The Standards Committee may withdraw a Reliability Standard, Interpretation or definition for good cause upon approval by the Board of Trustees. Upon approval by the Board of Trustees, NERC Staff will petition the Applicable Governmental Authorities, as needed, to allow for withdrawal. The Board of Trustees also has an independent right of withdrawal that is unaffected by the terms and conditions of this Section.

4.19: Retirement of a Reliability Standard, Interpretation, or Definition

The term "retirement" refers to the discontinuation of a Reliability Standard, Interpretation or definition that has been approved by Applicable Governmental Authorities. A Reliability Standard, Variance or Definition may be retired when it is superseded by a revised version, and in such cases the retirement of the

earlier version is to be noted in the implementation plan presented to the ballot pool for approval and the retirement shall be considered approved by the ballot pool upon ballot pool approval of the revised version.

Upon identification of a need to retire a Reliability Standard, Variance, Interpretation or definition, where the item will not be superseded by a new or revised version, a SAR containing the proposal to retire a Reliability Standard, Variance, Interpretation or definition will be posted for a comment period and ballot in the same manner as a Reliability Standard. The proposal shall include the rationale for the retirement and a statement regarding the impact of retirement on the reliability of the Bulk Power System. Upon approval by the Board of Trustees, NERC Staff will petition the Applicable Governmental Authorities to allow for retirement.

Section 5.0: Process for Developing a Defined Term

NERC maintains a glossary of approved terms, entitled the *Glossary of Terms Used in NERC Reliability Standards*[24] ("Glossary of Terms"). The Glossary of Terms includes terms that have been through the formal approval process and are used in one or more NERC Reliability Standards. Definitions shall not contain statements of performance Requirements. The Glossary of Terms is intended to provide consistency throughout the Reliability Standards.

There are several methods that can be used to add, modify or retire a defined term used in a continent-wide Reliability Standard.

- Anyone can use a Standard Authorization Request ("SAR") to submit a request to add, modify, or retire a defined term.
- Anyone can submit a Standards Comments and Suggestions Form recommending the addition, modification, or retirement of a defined term. (The suggestion would be added to a project and incorporated into a SAR.)
- A drafting team may propose to add, modify, or retire a defined term in conjunction with the work it is already performing.

5.1: Proposals to Develop a New or Revised Definition

The following considerations should be made when considering proposals for new or revised definitions:

- Some NERC Regional Entities have defined terms that have been approved for use in Regional Reliability Standards, and where the drafting team agrees with a term already defined by a Regional Entity, the same definition should be adopted if needed to support a NERC Reliability Standard.
- If a term is used in a Reliability Standard according to its common meaning (as found in a collegiate dictionary), the term shall not be proposed for addition to the Glossary of Terms.
- If a term has already been defined, any proposal to modify or delete that term shall consider all uses of the definition in approved Reliability Standards, with a goal of determining whether the proposed modification is acceptable, and whether the proposed modification would change the scope or intent of any approved Reliability Standards.
- When practical, where NAESB has a definition for a term, the drafting team shall use the same definition to support a NERC Reliability Standard.

Any definition that is balloted separately from a proposed new or modified Reliability Standard or from a proposal for retirement of a Reliability Standard shall be accompanied by an implementation plan.

If a SAR is submitted to the NERC Reliability Standards Staff with a proposal for a new or revised definition, the Standards Committee shall consider the urgency of developing the new or revised definition and may direct NERC Staff to post the SAR immediately, or may defer posting the SAR until a later time based on its priority relative to other projects already underway or already approved for future development. If the SAR identifies a term that is used in a Reliability Standard already under revision by a drafting team, the Standards Committee may direct the drafting team to add the term to the scope of the existing project. Each time the Standards Committee accepts a SAR for a project that was not identified in the *Reliability Standards Development Plan,* the project shall be added to the list of approved projects.

[24] The latest approved version of the Glossary of Terms is posted on the NERC website on the Standards web page.

5.2: Stakeholder Comments and Approvals

Any proposal for a new or revised definition shall be processed in the same manner as a Reliability Standard and quality review shall be conducted in parallel with this process. Once authorized by the Standards Committee, the proposed definition and its implementation plan shall be posted for at least one formal stakeholder comment period and shall be balloted in the same manner as a Reliability Standard. If a new or revised definition is proposed by a drafting team, that definition may be balloted separately from the associated Reliability Standard.

Each definition that is approved by its ballot pool shall be submitted to the NERC Board of Trustees for adoption and then filed with Applicable Governmental Authorities for approval in the same manner as a Reliability Standard.

Section 6.0: Processes for Conducting Field Tests and Collecting and Analyzing Data

While most drafting teams can develop their Reliability Standards without the need to conduct any field tests and without the need to collect and analyze data, some Reliability Standard development efforts may require field tests to analyze data and validate concepts in the development of Reliability Standards. Drafting teams are not required to collect and analyze data or to conduct a field test to validate a Reliability Standard.

6.1: Field Tests and Data Analysis for Validation of Concepts(collectively "Field Test")

1. Field tTests or collection and analysis of data to validate concepts that support the development of Requirements should be conducted before the SAR Standard Authorization Request ("SAR") for a project is finalized.
   If an entity wants to test a technical concept in support of a proposal for a new or revised Reliability Standard, the entity should either work with one of NERC's technical committees in collecting and analyzing the data or in conducting the field test, or the entity should submit a SAR with a request to collect and analyze data or conduct a field test to validate the concept prior to developing a new or revised Reliability Standard. The request to collect and analyze data or conduct a field test should include, at a minimum, either the data collection and analysis or field test plan, the implementation schedule, and an expectation for periodic updates of the analysis of the results. If the SAR sponsor has not collected and analyzed the data or conducted the field test, the Standards Committee may solicit support from NERC's technical committees or others in the industry. The results of the data collection and analysis or field test shall then be used to determine whether to add the SAR to the list of projects in the Reliability Standard Development Plan.
2. To conduct a Field Test of a technical concept in a proposed new or revised Reliability Standard, the requesting team must work with NERC staff to identify one of NERC's technical committees to lead the effort in conducting the Field Test.

6.1.1: Field Test Approval

The request to conduct a Field Test must include, at a minimum:

- the Field Test plan,
- the implementation schedule, and
- an expectation for periodic updates of the analysis of the results.

Prior to the requesting team conducting a Field Test, it must:

- first receive approval from the lead NERC technical committee, and
- subsequently receive approval from the Standards Committee.

6.1.2: Field Test Suspension

During the Field Test, if the lead NERC technical committee overseeing the Field Test determines there is a reliability risk to the BES:

- the lead NERC technical committee shall stop or modify the activity;
- the lead NERC technical committee shall inform the Standards Committee that the activity was stopped or modified;

- the Standards Committee, with the assistance of NERC staff, shall document the cessation or modification of the Field Test; and
- the Standards Committee shall notify NERC compliance staff to coordinate any compliance related issues such as continuance or cessation of waivers.

Prior to the Field Test being restarted after it has been stopped, the requesting team must resubmit the Field Test and receive approval as outlined in section 6.1.1.

If the Field Test does not provide sufficient information to formulate a conclusion within the time allotted in the plan, the Chair of the Standards Committee will work with the requesting team and the lead NERC technical committee to determine whether to continue, modify or terminate the Field Test.

If ~~a drafting team finds that it~~ the requesting team determines a need~~s~~ to ~~collect and analyze data or~~ conduct a ~~field~~ Field ~~test~~ Test of a concept that was not identified ~~when~~ in the SAR ~~was accepted, then the Standards Committee may direct the team to withdraw the SAR until the data has been collected and analyzed or until the field test has been conducted and the industry has had an opportunity to review the results for the impact on the scope of the proposed project~~it must create a supplemental SAR to include the Field Test and receive approval as outlined in section 6.1.1.

~~6.2: Field Tests and Data Analysis for Validation of Requirements~~

~~If a drafting team wants to conduct a field test or collect and analyze data to validate its proposed Requirements in a Reliability Standard, the team shall first obtain approval from the Standards Committee.[25] Drafting teams are not required to collect and analyze data or to conduct a field test to validate a Reliability Standard.~~

~~The request should include at a minimum the data collection and analysis or field test plan, the implementation schedule, and an expectation for periodic updates of the results. When authorizing a drafting team to collect and analyze data or to conduct a field test of one or more Requirements, the Standards Committee may request inputs on technical matters related from NERC's technical committees or industry experts, and may request the assistance of the Compliance Monitoring and Enforcement Program. All data collection and analysis and all field tests shall be concluded and the results incorporated into the Reliability Standard Requirements as necessary before proceeding to the formal comment period and subsequent balloting.~~

6.~~3~~2: Communication and Coordination for All Types of Field Tests ~~and Data Analyses~~

~~If the conduct of a field test (concepts or Requirements) or data collection and analysis could~~After approval of the Field Test, the requesting team may request waivers of compliance for Field Test participants that would be rendered ~~render Registered Entities~~ incapable of complying with the ~~current~~ Requirement(s) of ~~an approved~~the currently enforceable Reliability Standard ~~that is undergoing revision, the drafting team shall request a temporary waiver from compliance to those Requirements for entities participating in the field test~~due to their participation. ~~Upon request, the Standards Committee shall seek approval for the waiver from t~~The Compliance Monitoring and Enforcement Program staff ~~prior to the approval of the field test or data collection and analysis~~shall determine whether to approve the requested waivers, and the Standards staff shall inform the affected registered entities. Prior to initiation of the Field Test, the Chair of the Standards Committee, in conjunction with the lead NERC technical committee chair, shall inform the

[25] ~~The Process for Approving Data Collection and Analysis and Field Tests Associated with a Reliability Standard is posted on the Reliability Standards Resources web page.~~

NERC Board of the pending Field Test, the expected duration, and any requested waivers from compliance for registered entities.

During the Field Test, the requesting team conducting the Field Test shall provide periodic updates (no less than quarterly) on the progress of the Field Tests to the Standards Committee and the applicable NERC technical committees. The Chair of the Standards Committee shall keep the NERC Board informed.

Once a plan for a field test or a plan for data collection and analysis is approved, the NERC Reliability Standards Staff shall, under the direction of the Standards Committee, coordinate the implementation of the field test or data collection and analysis and shall provide official notice to the participants in the field test or data collection of any applicable temporary waiver to compliance with specific noted Requirements. The drafting team conducting the field test shall provide periodic updates on the progress of the field tests or data collection and analysis to the Standards Committee. The Standards Committee has the right to curtail a field test or data collection and analysis that is not implemented in accordance with the approved plan.

The field test plan or data collection and analysis plan, its approval, its participants, and all reports and results shall be publicly posted for stakeholder review on the Reliability Standards web page.

If a drafting team conducts or participates in a field test or in data collection and analysis (of concepts or Requirements), it shall provide a final report that identifies the results and how those results will be used.

Section 7.0: Process for Developing an Interpretation

A valid Interpretation request is one that requests additional clarity about one or more Requirements in approved NERC Reliability Standards, but does not request approval as to how to comply with one or more Requirements. A valid Interpretation response provides additional clarity about one or more Requirements, but does not expand on any Requirement and does not explain how to comply with any Requirement. Any entity that is directly and materially affected by the reliability of the North American Bulk Power Systems may request an Interpretation of any Requirement in any continent-wide Reliability Standard that has been adopted by the NERC Board of Trustees. Interpretations will only be provided for Board of Trustees-approved Reliability Standards *i.e.* (i) the current effective version of a Reliability Standard; or (ii) a version of a Reliability Standard with a future effective date.

An Interpretation may only clarify or interpret the Requirements of an approved Reliability Standard, including, if applicable, any attachment referenced in the Requirement being clarified. No other elements of an approved Reliability Standard are subject to Interpretation.

The entity requesting the Interpretation shall submit a *Request for Interpretation* form[26] to the NERC Reliability Standards Staff explaining the clarification required, the specific circumstances surrounding the request, and the impact of not having the Interpretation provided. The NERC Reliability Standards and Legal Staffs shall review the request for interpretation to determine whether it meets the requirements for a valid interpretation. Based on this review, the NERC Standards and Legal Staffs shall make a recommendation to the Standards Committee whether to accept the request for Interpretation and move forward in responding to the Interpretation request.

For example, an Interpretation request may be rejected where it:

(1) Requests approval of a particular compliance approach;
(2) Identifies a gap or perceived weakness in the approved Reliability Standard;
(3) Where an issue can be addressed by an active standard drafting team;
(4) Where it requests clarification of any element of a Reliability Standard other than a Requirement;
(5) Where a question has already been addressed in the record;
(6) Where the Interpretation identifies an issue and proposes the development of a new or modified Reliability Standard, (such issues should be addressed via submission of a SAR);
(7) Where an Interpretation seeks to expand the scope of a Reliability Standard; or
(8) Where the meaning of a Reliability Standard is plain on its face.

If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for rejecting the Interpretation to the entity requesting the Interpretation within 10 business days of the decision to reject. If the Standards Committee accepts the Interpretation request, the NERC Standards Staff shall (i) form a ballot pool and (ii) assemble an Interpretation drafting team with the relevant expertise to address the interpretation for approval by the Standards Committee. As soon as practical, the team shall develop a "final draft" Interpretation providing the requested clarity.

Interpretations will be balloted in the same manner as Reliability Standards.

[26] The *Request for Interpretation* form is posted on the NERC Standards web page.

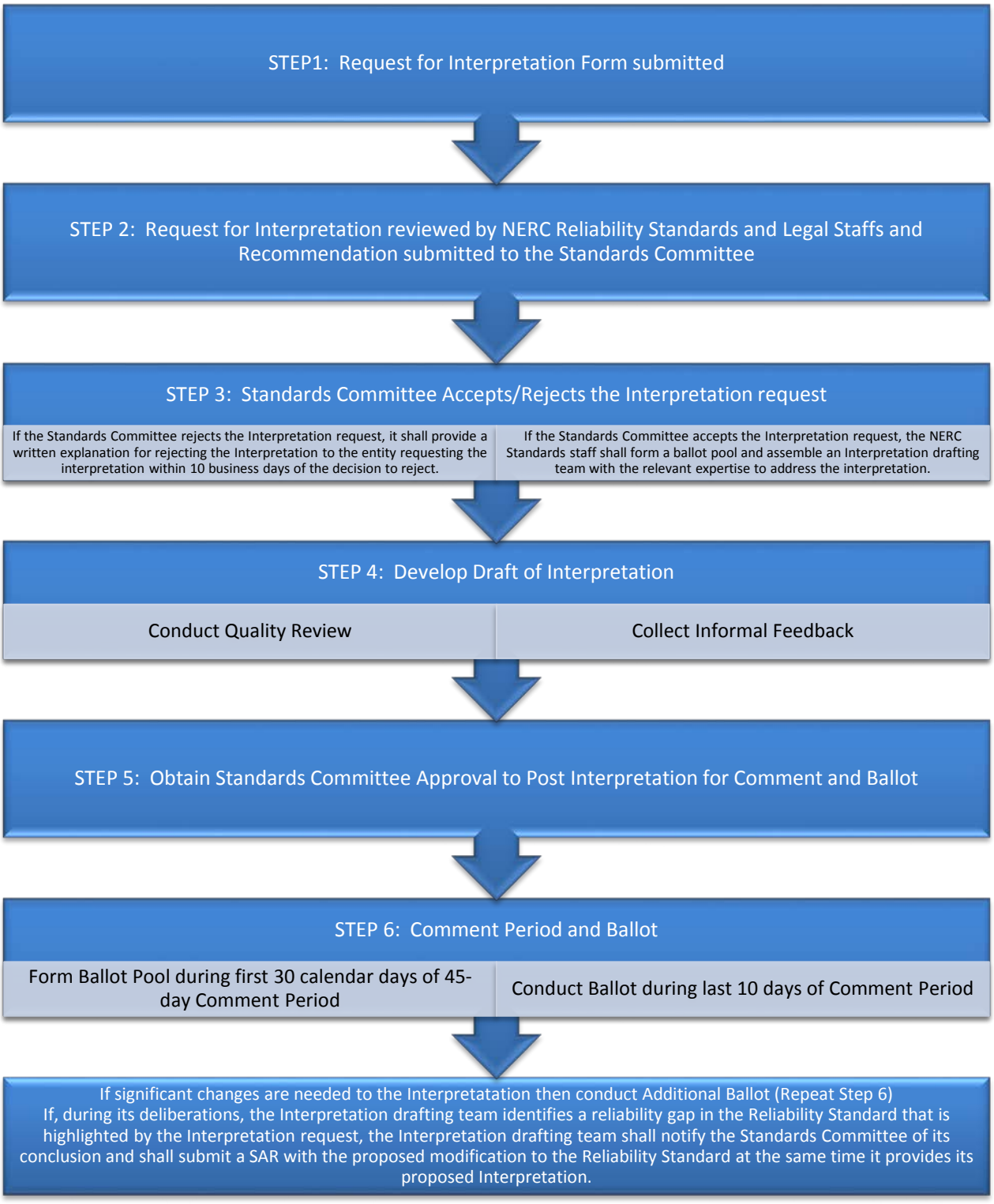
If stakeholder comments indicate that there is not a consensus for the Interpretation, and the Interpretation drafting team cannot revise the Interpretation without violating the basic expectations outlined above, the Interpretation drafting team shall notify the Standards Committee of its conclusion and may submit a SAR with the proposed modification to the Reliability Standard. The entity that requested the Interpretation shall be notified and the disposition of the Interpretation shall be posted.

If, during its deliberations, the Interpretation drafting team identifies a reliability gap in the Reliability Standard that is highlighted by the Interpretation request, the Interpretation drafting team shall notify the Standards Committee of its conclusion and may submit a SAR with the proposed modification to the Reliability Standard at the same time it provides its proposed Interpretation.

The NERC Reliability Standards and Legal Staffs shall review the final Interpretation to determine whether it has met the requirements for a valid Interpretation. Based on this review, the NERC Standards and Legal Staffs shall make a recommendation to the NERC Board of Trustees regarding adoption.

If approved by its ballot pool, the Interpretation shall be forwarded to the NERC Board of Trustees for adoption.[27] If an Interpretation drafting team proposes a modification to a Reliability Standard as part of its work in developing an Interpretation, the Board of Trustees shall be notified of this proposal at the time the Interpretation is submitted for adoption. Following adoption by the Board of Trustees, NERC Staff shall file the Interpretation for approval by Applicable Governmental Authorities and the Interpretation shall become effective when approved by those Applicable Governmental Authorities. The Interpretation shall stand until such time as the Interpretation can be incorporated into a future revision of the Reliability Standard or the Interpretation is retired due to a future modification of the applicable Requirement.

[27] NERC will maintain a record of all interpretations associated with each standard on the Reliability Standards page of the NERC website.


STEP1: Request for Interpretation Form submitted
STEP 2: Request for Interpretation reviewed by NERC Reliability Standards and Legal Staffs and Recommendation submitted to the Standards Committee
STEP 3: Standards Committee Accepts/Rejects the Interpretation request
If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for rejecting the Interpretation to the entity requesting the interpretation within 10 business days of the decision to reject.
If the Standards Committee accepts the Interpretation request, the NERC Standards staff shall form a ballot pool and assemble an Interpretation drafting team with the relevant expertise to address the interpretation.
STEP 4: Develop Draft of Interpretation
Conduct Quality Review
Collect Informal Feedback
STEP 5: Obtain Standards Committee Approval to Post Interpretation for Comment and Ballot
STEP 6: Comment Period and Ballot
Form Ballot Pool during first 30 calendar days of 45-day Comment Period
Conduct Ballot during last 10 days of Comment Period
If significant changes are needed to the Interpretatation then conduct Additional Ballot (Repeat Step 6)
If, during its deliberations, the Interpretation drafting team identifies a reliability gap in the Reliability Standard that is highlighted by the Interpretation request, the Interpretation drafting team shall notify the Standards Committee of its conclusion and shall submit a SAR with the proposed modification to the Reliability Standard at the same time it provides its proposed Interpretation.

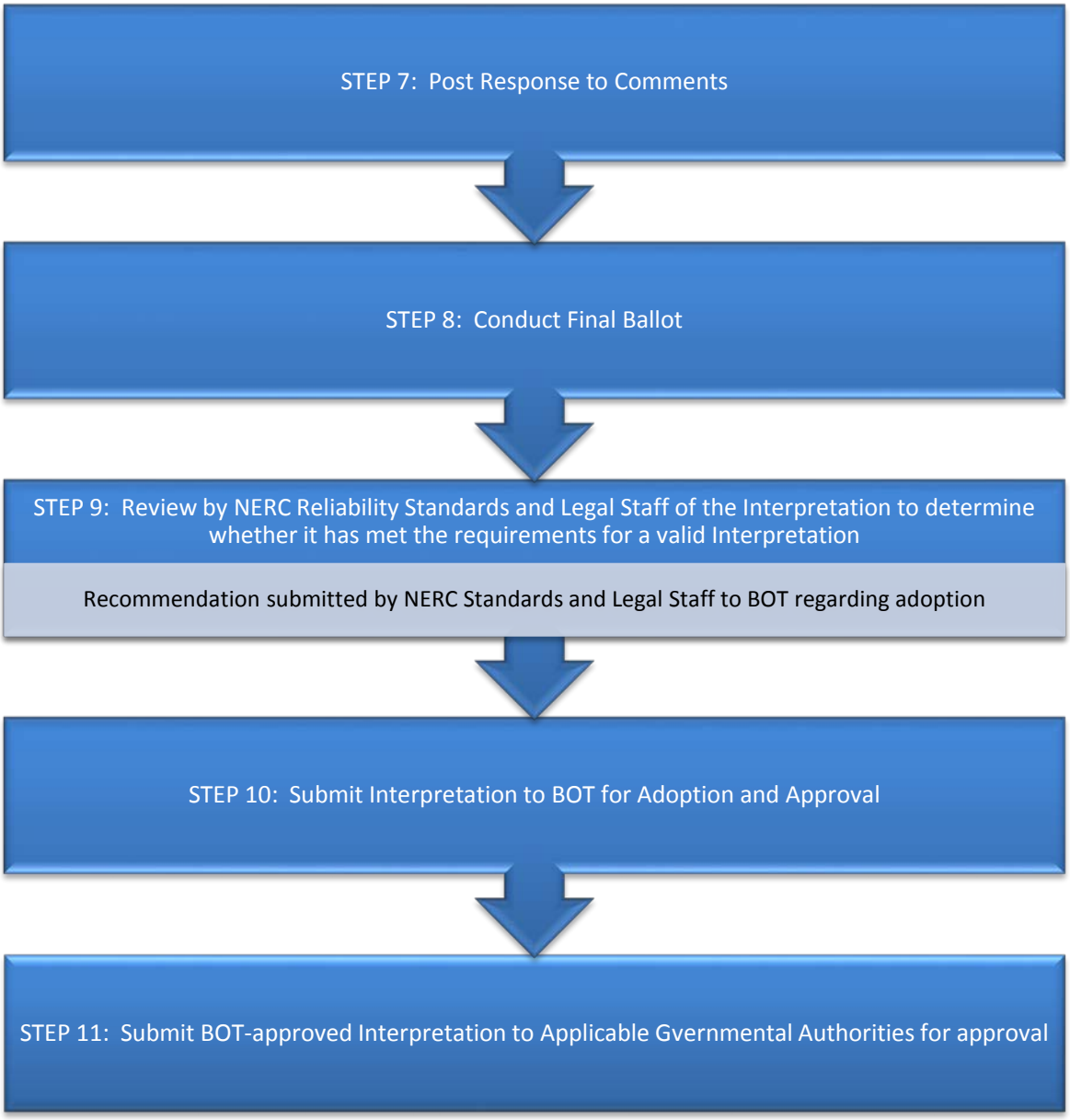


FIGURE 2: Process for Developing an Interpretation

Section 8.0: Process for Appealing an Action or Inaction

Any entity that has directly and materially affected interests and that has been or will be adversely affected by any procedural action or inaction related to the development, approval, revision, reaffirmation, retirement or withdrawal of a Reliability Standard, definition, Variance, associated implementation plan, or Interpretation shall have the right to appeal. This appeals process applies only to the NERC Reliability Standards processes as defined in this manual, not to the technical content of the Reliability Standards action.

The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made in writing within 30 days of the date of the action purported to cause the adverse effect, except appeals for inaction, which may be made at any time. The final decisions of any appeal shall be documented in writing and made public.

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

8.1: Level 1 Appeal

Level 1 is the required first step in the appeals process. The appellant shall submit (to the Director of Standards) a complaint in writing that describes the procedural action or inaction associated with the Reliability Standards process. The appellant shall describe in the complaint the actual or potential adverse impact to the appellant. Assisted by NERC Staff and industry resources as needed, the Director of Standards shall prepare a written response addressed to the appellant as soon as practical but not more than 45 days after receipt of the complaint. If the appellant accepts the response as a satisfactory resolution of the issue, both the complaint and response shall be made a part of the public record associated with the Reliability Standard.

8.2: Level 2 Appeal

If after the Level 1 Appeal the appellant remains unsatisfied with the resolution, as indicated by the appellant in writing to the Director of Standards, the Director of Standards shall convene a Level 2 Appeals Panel. This panel shall consist of five members appointed by the Board of Trustees. In all cases, Level 2 Appeals Panel members shall have no direct affiliation with the participants in the appeal.

The NERC Reliability Standards Staff shall post the complaint and other relevant materials and provide at least 30 days notice of the meeting of the Level 2 Appeals Panel. In addition to the appellant, any entity that is directly and materially affected by the procedural action or inaction referenced in the complaint shall be heard by the panel. The panel shall not consider any expansion of the scope of the appeal that was not presented in the Level 1 Appeal. The panel may, in its decision, find for the appellant and remand the issue to the Standards Committee with a statement of the issues and facts in regard to which fair and equitable action was not taken. The panel may find against the appellant with a specific statement of the facts that demonstrate fair and equitable treatment of the appellant and the appellant's objections. The panel may not, however, revise, approve, disapprove, or adopt a Reliability Standard, definition, Variance or Interpretation or implementation plan as these responsibilities remain with the ballot pool and Board of Trustees respectively. The actions of the Level 2 Appeals Panel shall be publicly posted.

In addition to the foregoing, a procedural objection that has not been resolved may be submitted to the Board of Trustees for consideration at the time the Board decides whether to adopt a particular Reliability Standard, definition, Variance or Interpretation. The objection shall be in writing, signed by an officer of the objecting entity, and contain a concise statement of the relief requested and a clear demonstration of the

facts that justify that relief. The objection shall be filed no later than 30 days after the announcement of the vote by the ballot pool on the Reliability Standard in question.

Section 9.0: Process for Developing a Variance

A Variance is an approved, alternative method of achieving the reliability intent of one or more Requirements in a Reliability Standard. No Regional Entity or Bulk Power System owner, operator, or user shall claim a Variance from a NERC Reliability Standard without approval of such a Variance through the relevant Reliability Standard approval procedure for the Variance. Each Variance from a NERC Reliability Standard that is approved by NERC and Applicable Governmental Authorities shall be made an enforceable part of the associated NERC Reliability Standard.

NERC's drafting teams shall aim to develop Reliability Standards with Requirements that apply on a continent-wide basis, minimizing the need for Variances while still achieving the Reliability Standard's reliability objectives. If one or more Requirements cannot be met or complied with as written because of a physical difference in the Bulk Power System or because of an operational difference (such as a conflict with a federally or provincially approved tariff), but the Requirement's reliability objective can be achieved in a different fashion, an entity or a group of entities may pursue a Variance from one or more Requirements in a continent-wide Reliability Standard. It is the responsibility of the entity that needs a Variance to identify that need and initiate the processing of that Variance through the submittal of a SAR[28] that includes a clear definition of the basis for the Variance.

There are two types of Variances – those that apply on an Interconnection-wide basis, and those that apply to one or more entities on less than an Interconnection-wide basis.

9.1: Interconnection-wide Variances

Any Variance from a NERC Reliability Standard Requirement that is proposed to apply to Registered Entities within a Regional Entity organized on an Interconnection-wide basis shall be considered an Interconnection-wide Variance and shall be developed through that Regional Entity's NERC-approved Regional Reliability Standards development procedure.

While an Interconnection-wide Variance may be developed through the associated Regional Reliability Standards development process, Regional Entities are encouraged to work collaboratively with existing continent-wide drafting teams to reduce potential conflicts between the two efforts.

An Interconnection-wide Variance from a NERC Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the associated NERC Reliability Standard. NERC shall rebuttably presume that an Interconnection-wide Variance from a NERC Reliability Standard that is developed, in accordance with a Regional Reliability Standards development procedure approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

9.2: Variances that Apply on Less than an Interconnection-wide Basis

Any Variance from a NERC Reliability Standard Requirement that is proposed to apply to one or more entities but less than an entire Interconnection (*e.g.*, a Variance that would apply to a regional transmission organization or particular market or to a subset of Bulk Power System owners, operators, or users), shall be considered a Variance. A Variance may be requested while a Reliability Standard is under development or a Variance may be requested at any time after a Reliability Standard is approved. Each request for a

[28] A sample of a SAR that identifies the need for a Variance and a sample Variance are posted as resources on the Reliability Standards Resources web page.

Variance shall be initiated through a SAR, and processed and approved in the same manner as a continent-wide Reliability Standard, using the Reliability Standards development process defined in this manual.

Section 10.0: Processes for Developing a Reliability Standard Related to a Confidential Issue

While it is NERC's intent to use its ANSI-accredited Reliability Standards development process for developing its Reliability Standards, NERC has an obligation as the ERO to ensure that there are Reliability Standards in place to preserve the reliability of the interconnected Bulk Power Systems throughout North America. When faced with a national security emergency situation, NERC may use one of the following special processes to develop a Reliability Standard that addresses an issue that is confidential. Reliability Standards developed using one of the following processes shall be called, "special Reliability Standards" and shall not be filed with ANSI for approval as American National Standards.

The NERC Board of Trustees may direct the development of a new or revised Reliability Standard to address a national security situation that involves confidential issues. These situations may involve imminent or long-term threats. In general, these Board directives will be driven by information from the President of the United States of America or the Prime Minister of Canada or a national security agency or national intelligence agency of either or both governments indicating (to the ERO) that there is a national security threat to the reliability of the Bulk Power System.[29]

There are two special processes for developing Reliability Standards responsive to confidential issues – one process where the confidential issue is "imminent," and one process where the confidential issue is "not imminent."

10.1: Process for Developing Reliability Standards Responsive to Imminent, Confidential Issues
If the NERC Board of Trustees directs the immediate development of a new or revised Reliability Standard to address a confidential national security emergency situation, the NERC Reliability Standards Staff shall develop a SAR, form a ballot pool (to vote on the Reliability Standard and its implementation plan) and assemble a slate of pre-defined subject matter experts as a proposed drafting team for approval by the Standards Committee's officers. All members of the Registered Ballot Body shall have the opportunity to join the ballot pool.

10.2: Drafting Team Selection
The Reliability Standard drafting team selection process shall be limited to just those candidates who have already been identified as having the appropriate security clearance, the requisite technical expertise, and either have signed or are willing to sign a strict confidentiality agreement.

10.3: Work of Drafting Team
The Reliability Standard drafting team shall perform all its work under strict security and confidential rules. The Reliability Standard drafting team shall develop the new or revised Reliability Standard and its implementation plan.

The Reliability Standard drafting team shall review its work, to the extent practical, as it is being developed with officials from the appropriate governmental agencies in the U.S. and Canada, under strict security and confidentiality rules.

10.4: Formal Stakeholder Comment & Ballot Window

[29] The NERC Board may direct the immediate development and issuance of a Level 3 (Essential Action) alert and then may also direct the immediate development of a new or revised Reliability Standard.

The draft Reliability Standard and its implementation plan shall be distributed for a formal comment period, under strict confidentiality rules, only to those entities that are listed in the NERC Compliance Registry to perform one of the functions identified in the applicability section of the Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.[30] At the same time, the Reliability Standard shall be distributed to the members of the ballot pool for review and ballot. The NERC Reliability Standards Staff shall not post or provide the ballot pool with any confidential background information.

The drafting team, working with the NERC Reliability Standards Staff, shall consider and respond to all comments, make any necessary conforming changes to the Reliability Standard and its implementation plan, and shall distribute the comments, responses and any revision to the same population as received the initial set of documents for formal comment and ballot.

10.5: Board of Trustee Actions
Each Reliability Standard and implementation plan developed through this process shall be submitted to the NERC Board of Trustees for adoption.

10.6: Governmental Approvals
All approved documents shall be filed for approval with Applicable Governmental Authorities.

[30] In this phase of the process, only the proposed Reliability Standard shall be distributed to those entities expected to comply, not the rationale and justification for the Reliability Standard. Only the special drafting team members, who have the appropriate security credentials, shall have access to this rationale and justification.

10.7: Developing a Reliability Standard Responsive to an Imminent, Confidential Issue

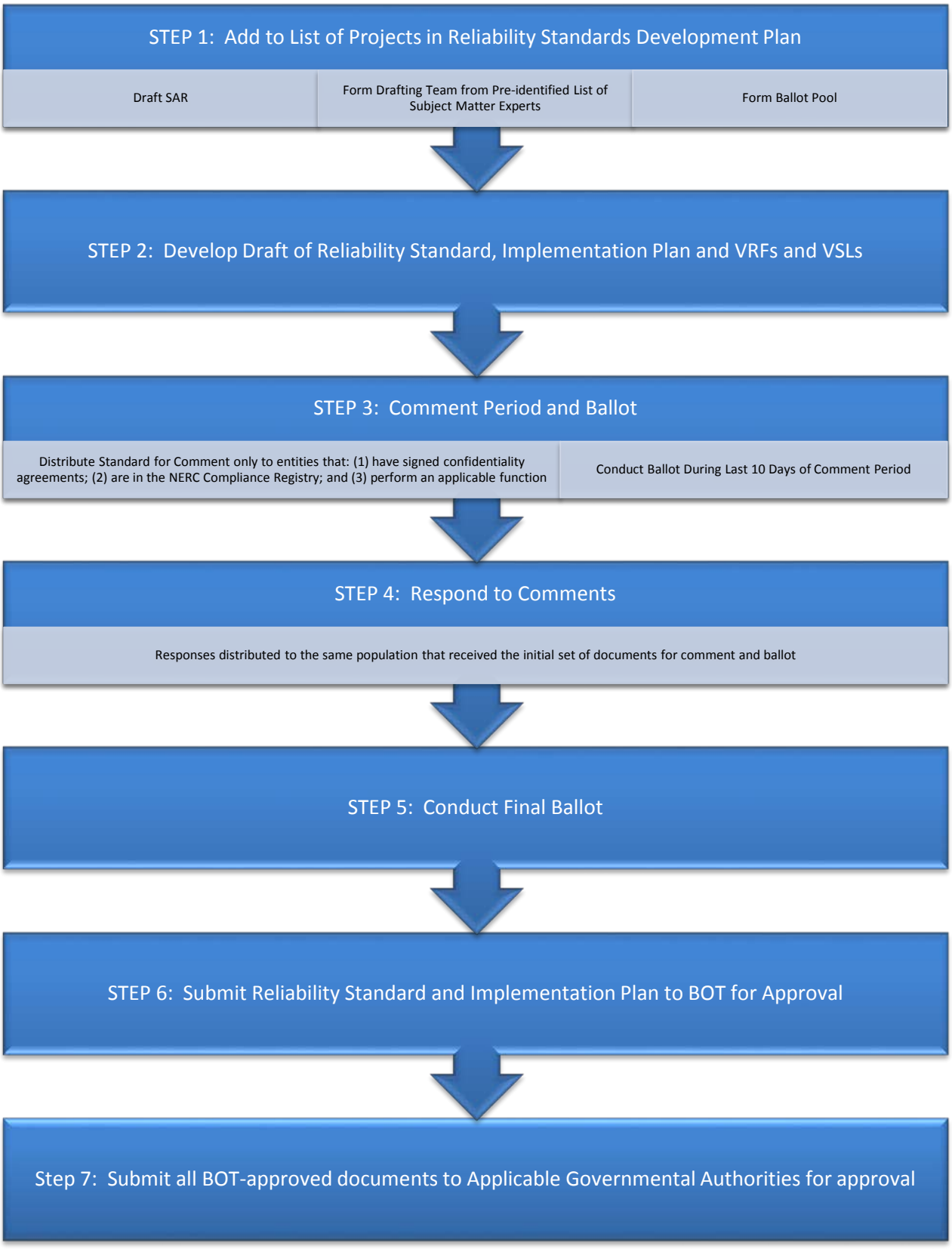


FIGURE 3: Process for Developing a Standard Responsive to an Imminent, Confidential Issue

10.8: Process for Developing Reliability Standards Responsive to Non-imminent, Confidential Issues

If the NERC Board of Trustees directs the immediate development of a new or revised Reliability Standard to address a confidential national security emergency situation, the NERC Reliability Standards Staff shall develop a SAR, form a ballot pool (to vote on the Reliability Standard and its implementation plan) and assemble a slate of pre-defined subject matter experts as a proposed drafting team for approval by the Standards Committee's officers. All members of the Registered Ballot Body shall have the opportunity to join the ballot pool.

10.9: Drafting Team Selection

The drafting team selection process shall be limited to just those candidates who have already been identified as having the appropriate security clearance, the requisite technical expertise, and either have signed or are willing to sign a strict confidentiality agreement.

10.10: Work of Drafting Team

The drafting team shall perform all its work under strict security and confidential rules. The Reliability Standard drafting team shall develop the new or revised Reliability Standard and its implementation plan.

The drafting team shall review its work, to the extent practical, as it is being developed with officials from the Applicable Governmental Authorities, under strict security and confidentiality rules.

10.11: Formal Stakeholder Comment & Ballot Window

The draft Reliability Standard and its implementation plan shall be distributed for a formal comment period, under strict confidentiality rules, only to those entities that are listed in the NERC Compliance Registry to perform one of the functions identified in the applicability section of the Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.[31] At the same time, the Reliability Standard shall be distributed to the members of the ballot pool for review and ballot. The NERC Reliability Standards Staff shall not post or provide the ballot pool with any confidential background information.

10.12: Revisions to Reliability Standard, Implementation Plan and VRFs and VSLs

The drafting team, working with the NERC Reliability Standards Staff, shall work to refine the Reliability Standard, implementation plan and VRFs and VSLs in the same manner as for a new Reliability Standard following the "normal" Reliability Standards development process described earlier in this manual with the exception that distribution of the comments, responses, and new drafts shall be limited to those entities that are in the ballot pool and those entities that are listed in the NERC Compliance Registry to perform one of the functions identified in the applicability section of the Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.

10.13: Board of Trustee Action

Each Reliability Standard, implementation plan, and the associated VRFs and VSLs developed through this process shall be submitted to the NERC Board of Trustees for adoption.

10.14: Governmental Approvals

All BOT-approved documents shall be filed for approval with Applicable Governmental Authorities.

[31] In this phase of the process, only the proposed Reliability Standard shall be distributed to those entities expected to comply, not the rationale and justification for the Reliability Standard. Only the special drafting team members, who have the appropriate security credentials, shall have access to this rationale and justification.

Developing a Reliability Standard Responsive to a Non-imminent, Confidential Issue

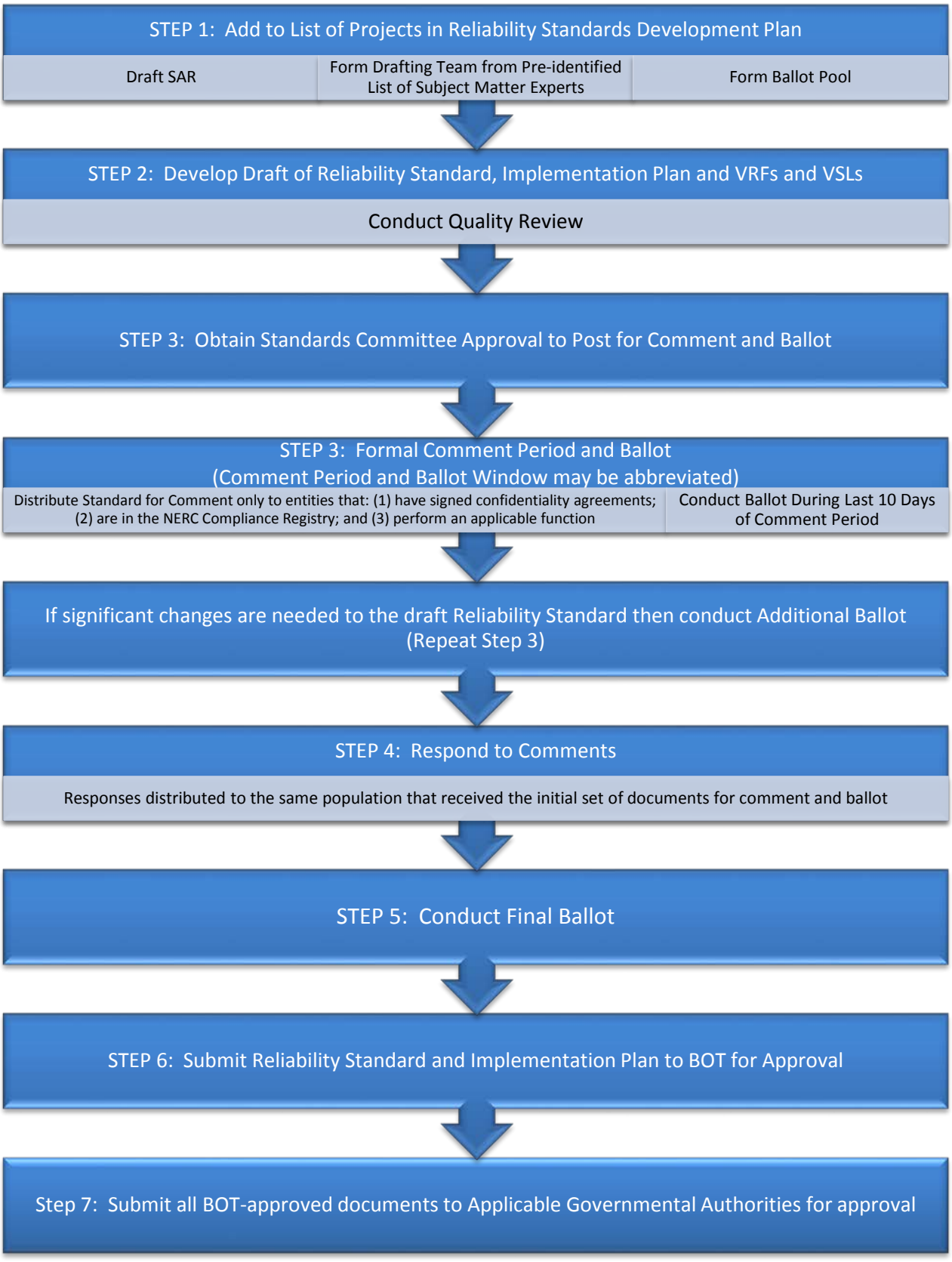


FIGURE 4: Developing a Standard Responsive to a Non-Imminent, Confidential Issue

Section 11.0: Process for Approving Supporting Documents

The following types of documents are samples of the types of supporting documents that may be developed to enhance stakeholder understanding and implementation of a Reliability Standard. These documents may explain or facilitate implementation of Reliability Standards but do not themselves contain mandatory Requirements subject to compliance review. Any Requirements that are mandatory shall be incorporated into the Reliability Standard in the Reliability Standard development process.

While most supporting documents are developed by the standard drafting team working to develop the associated Reliability Standard, any entity may develop a supporting document associated with a Reliability Standard.

The Standards Committee shall authorize the posting of all supporting references[32] that are linked to an approved Reliability Standard. Prior to granting approval to post a supporting reference with a link to the associated Reliability Standard, the Standards Committee shall verify that the document has had stakeholder review to verify the accuracy of the technical content. While the Standards Committee has the authority to approve the posting of each such reference, stakeholders, not the Standards Committee, verify the accuracy of the document's contents.

Type of Document	Description
Reference	Descriptive, technical information or analysis or explanatory information to support the understanding and interpretation of a Reliability Standard. A standard reference may support the implementation of a Reliability Standard or satisfy another purpose consistent with the reliability and market interface principles.
Guideline	Recommended process that identifies a method of meeting a Requirement under specific conditions.
Supplement	Data forms, pro forma documents, and associated instructions that support the implementation of a Reliability Standard.
Training Material	Documents that support the implementation of a Reliability Standard.
Procedure	Step-wise instructions defining a particular process or operation. Procedures may support the implementation of a Reliability Standard or satisfy another purpose consistent with the reliability and market interface principles.
White Paper	An informal paper stating a position or concept. A white paper may be used to propose preliminary concepts for a Reliability Standard or one of the documents above.

[32] The Standards Committee's Procedure for Approving the Posting of Reference Documents is posted on the Reliability Standards Resources web page.

Section 12.0: Process for Correcting Errata

From time to time, an error may be discovered in a Reliability Standard. Such errors may be corrected (i) following a Final Ballot prior to Board of Trustees adoption, (ii) following Board of Trustees adoption prior to filing with Applicable Governmental Authorities; and (iii) following filing with Applicable Governmental Authorities. If the Standards Committee agrees that the correction of the error does not change the scope or intent of the associated Reliability Standard, and agrees that the correction has no material impact on the end users of the Reliability Standard, then the correction shall be filed for approval with Applicable Governmental Authorities as appropriate. The NERC Board of Trustees has resolved to concurrently approve any errata approved by the Standards Committee.

Section 13.0: Process for Conducting Periodic Reviews of Reliability Standards

All Reliability Standards shall be reviewed at least once every ten years from the effective date of the Reliability Standard or the date of the latest Board of Trustees adoption to a revision of the Reliability Standard, whichever is later. If a Reliability Standard is approved by ANSI as an American National Standard, it shall be reviewed at least once every five years from the effective date of the Reliability Standard or the date of the latest Board of Trustees adoption to a revision of the Reliability Standard, whichever is later.

The *Reliability Standards Development Plan* shall include projects that address this five or ten-year review of Reliability Standards.

- If a Reliability Standard is nearing its five or ten-year review and has issues that need resolution, then the *Reliability Standards Development Plan* shall include a project for the complete review and associated revision of that Reliability Standard that includes addressing all outstanding governmental directives, all approved Interpretations, and all unresolved issues identified by stakeholders.
- If a Reliability Standard is nearing its five or ten-year review and there are no outstanding governmental directives, Interpretations, or unresolved stakeholder issues associated with that Reliability Standard, then the Reliability *Standards Development Plan* shall include a project solely for the "five-year review" of that Reliability Standard.

For a project that is focused solely on the five-year review, the Standards Committee shall appoint a review team of subject matter experts to review the Reliability Standard and recommend whether the American National Standard Institute-approved Reliability Standard should be reaffirmed, revised, or withdrawn. Each review team shall post its recommendations for a 45 calendar day formal stakeholder comment period and shall provide those stakeholder comments to the Standards Committee for consideration.

- If a review team recommends reaffirming a Reliability Standard, the Standards Committee shall submit the reaffirmation to the Board of Trustees for adoption and then to Applicable Governmental Authorities for approval. Reaffirmation does not require approval by stakeholder ballot.
- If a review team recommends modifying, or retiring a Reliability Standard, the team shall develop a SAR with such a proposal and the SAR shall be submitted to the Standards Committee for prioritization as a new project. Each existing Reliability Standard recommended for modification, or retirement shall remain in effect in accordance with the associated implementation plan until the action to modify or withdraw the Reliability Standard is approved by its ballot pool, adopted by the Board of Trustees, and approved by Applicable Governmental Authorities.

In the case of reaffirmation of a Reliability Standard, the Reliability Standard shall remain in effect until the next five or ten-year review or until the Reliability Standard is otherwise modified or withdrawn by a separate action.

Section 14.0: Public Access to Reliability Standards Information

14.1: Online Reliability Standards Information System

The NERC Reliability Standards Staff shall maintain an electronic copy of information regarding currently proposed and currently in effect Reliability Standards. This information shall include current Reliability Standards in effect, proposed revisions to Reliability Standards, and proposed new Reliability Standards. This information shall provide a record, for at a minimum the previous five years, of the review and approval process for each Reliability Standard, including public comments received during the development and approval process.

14.2: Archived Reliability Standards Information

The NERC Staff shall maintain a historical record of Reliability Standards information that is no longer maintained online. Archived information shall be retained indefinitely as practical, but in no case less than five years or one complete standard cycle from the date on which the Reliability Standard was no longer in effect. Archived records of Reliability Standards information shall be available electronically within 30 days following the receipt by the NERC Reliability Standards Staff of a written request.

Section 15.0: Process for Updating Standard Processes

15.1: Requests to Revise the Standard Processes Manual

Any person or entity may submit a request to modify one or more of the processes contained within this manual. The Standards Committee shall oversee the handling of each request. The Standards Committee shall prioritize all requests, merge related requests, and respond to each sponsor within 30 calendar days.

The Standards Committee shall post the proposed revisions for a 45 (calendar) day formal comment period. Based on the degree of consensus for the revisions, the Standards Committee shall:

a. Submit the revised process or processes for ballot pool approval;
b. Repeat the posting for additional inputs after making changes based on comments received;
c. Remand the proposal to the sponsor for further work; or
d. Reject the proposal.

The Registered Ballot Body shall be represented by a ballot pool. The ballot procedure shall be the same as that defined for approval of a Reliability Standard, including the use of an Additional Ballot if needed. If the proposed revision is approved by the ballot pool, the Standards Committee shall submit the revised procedure to the Board for adoption. The Standards Committee shall submit to the Board a description of the basis for the changes, a summary of the comments received, and any minority views expressed in the comment and ballot process. The proposed revisions shall not be effective until approved by the NERC Board of Trustees and Applicable Governmental Authorities.

Section 16.0: Waiver

While it is NERC's intent to use its ANSI-accredited Reliability Standards development process for developing its Reliability Standards, NERC may need to develop a new or modified Reliability Standard, definition, Variance, or implementation plan under specific time constraints (such as to meet a time constrained regulatory directive) or to meet an urgent reliability issue such that there isn't sufficient time to follow all the steps in the normal Reliability Standards development process.

The Standards Committee may waive any of the provisions contained in this manual for good cause shown, but limited to the following circumstances:

- In response to a national emergency declared by the United States or Canadian government that involves the reliability of the Bulk Electric System or cyber attack on the Bulk Electric System;
- Where necessary to meet regulatory deadlines;
- Where necessary to meet deadlines imposed by the NERC Board of Trustees; or
- Where the Standards Committee determines that a modification to a proposed Reliability Standard or its Requirement(s), a modification to a defined term, a modification to an interpretation, or a modification to a variance has already been vetted by the industry through the standards development process or is so insubstantial that developing the modification through the processes contained in this manual will add significant time delay.

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

A waiver request may be submitted to the Standards Committee by any entity or individual, including NERC committees or subgroups and NERC Staff. Prior to consideration of any waiver request, the Standards Committee must provide five business days notice to stakeholders.

Action on the waiver request will be included in the minutes of the Standards Committee. Following the approval of the Standards Committee to waive any provision of the Standard Process Manual, the Standards Committee will report this decision to the Standards Oversight and Technology Committee.[33] Actions taken pursuant to an approved waiver request will be posted on the Standard Project page and included in the next project announcement.

In addition, the Standards Committee shall report the exercise of this waiver provision to the Board of Trustees prior to adoption of the related Reliability Standard, Interpretation, definition or Variance.

Reliability Standards developed as a result of a waiver of any provision of the Standard Processes Manual shall not be filed with ANSI for approval as American National Standards.

[33] Any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.

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Enhanced Periodic Review Standing Review Team - Standards Grading

Final Grades for Standards Graded in 2016

The Enhanced Periodic Review (EPR) Standing Review Team (SRT) was tasked with using metrics from the 2013 Independent Experts Review Panel to assign numeric grades to instruct future EPR teams. While the SRT's final standards grades are important data points for the EPRs to consider, they are intended as one of many inputs to facilitate discussion during the reviews.

The EPRSRT completed the initial grading of eligible Reliability Standards, which NERC posted for a 30-day stakeholder comment period. The EPR SRT conducted a second public meeting in which it considered input from stakeholders and held additional discussion prior to reaching consensus to finalize the grades. Shown below are the average SRT grades for content (0-3) and quality (0-12) for each of the standard requirements eligible for EPR in 2016-2017. Detailed analysis and background information on the Standards Grading process can be found on the project page.

Standard and Requirement	Content Average	Quality Average
BAL-001-2 , R1	3.00	11.5
BAL-001-2 , R2	3.00	11
EOP-010-1, R1	3.00	12
EOP-010-1, R2	2.67	10
EOP-010-1, R3.	3.00	11.75
EOP-011-1, R1.	3.00	11.5
EOP-011-1, R2.	3.00	12
EOP-011-1, R3.	2.50	10.75
EOP-011-1, R4.	2.50	11
EOP-011-1, R5.	2.75	11.75
EOP-011-1, R6.	2.75	11.5
FAC-008-3, R1	3.00	10.75
FAC-008-3, R2.	3.00	11.33333
FAC-008-3, R3.	3.00	11.5
FAC-008-3, R6.	3.00	11
FAC-008-3, R7.	2.50	10.5
FAC-008-3, R8.	2.75	10.25
INT-004-3.1, R3.	3.00	11.25
INT-006-4, R1	3.00	11
INT-006-4, R2	3.00	11.25
INT-006-4, R3.	3.00	11.5
INT-006-4, R4	3.00	11.25
INT-006-4, R5	3.00	11.75
INT-009-2.1, R1	3.00	11.5
INT-009-2.1, R2	3.00	12

Standard and Requirement	Content Average	Quality Average
INT-009-2.1, R3.	3.00	12
INT-010-2.1, R1	3.00	11
INT-010-2.1, R2	3.00	11.5
INT-010-2.1, R3.	3.00	11
NUC-001-3, R1	3.00	12
NUC-001-3, R2.	3.00	12
NUC-001-3, R3.	2.75	12
NUC-001-3, R4.	3.00	11.75
NUC-001-3, R5.	3.00	12
NUC-001-3, R6.	3.00	12
NUC-001-3, R7.	3.00	12
NUC-001-3, R8.	3.00	12
NUC-001-3, R9	3.00	11.75
PER-003-1, R1.	3.00	11.5
PER-003-1, R2.	3.00	11.5
PER-003-1, R3.	3.00	11.5
PER-004-2, R1.	2.75	11.25
PER-004-2, R2.	3.00	9.5
PRC-004-5(i), R1.	2.75	11.75
PRC-004-5(i), R2.	3.00	11.75
PRC-004-5(i), R3.	3.00	11.25
PRC-004-5(i), R4.	3.00	11.5
PRC-004-5(i), R5.	3.00	11.5
PRC-004-5(i), R6.	3.00	11.5
PRC-005-6, R1.	2.75	11.25

Standard and Requirement	Content Average	Quality Average
PRC-005-6, R2.	3.00	11.5
PRC-005-6, R3.	3.00	11.5
PRC-005-6, R4.	3.00	11.5
PRC-005-6, R5.	2.75	10.5
PRC-006-2, R1.	3.00	11.5
PRC-006- , R11.	3.00	12
PRC-006-2, R12.	3.00	11.75
PRC-006-2, R13.	3.00	12
PRC-006-2, R2.	2.00	11.5
PRC-006-2, R3.	3.00	11.5
PRC-006-2, R4.	3.00	11.75
PRC-006-2, R5.	3.00	11.75
PRC-006-2, R6.	3.00	11.75
PRC-006-2, R7.	3.00	12
PRC-006-2, R8.	3.00	11.75
PRC-006-2, R9.	3.00	11.5
PRC-010-2, R1.	2.50	11.5
PRC-010-2, R2.	3.00	11.5
PRC-010-2, R3.	2.50	11.25
PRC-010-2, R4.	2.50	12
PRC-010-2, R5.	2.50	12
PRC-010-2, R6.	3.00	11.5
PRC-010-2, R7.	3.00	12
PRC-010-2, R8.	3.00	12
PRC-019-2, R1.	3.00	11.75

Standard and Requirement	Content Average	Quality Average
PRC-019-2, R2.	3.00	11.75
PRC-023-4, R1.	3.00	11.25
PRC-023-4, R2.	2.75	11.25
PRC-023-4, R3.	2.75	11.75
PRC-023-4, R4.	2.75	11.5
PRC-023-4, R5.	3.00	11.25
PRC-023-4, R6.	3.00	11.75
PRC-024-2, R1.	3.00	11.75
PRC-024-2, R2.	3.00	11.75
PRC-024-2, R3.	3.00	11.5
PRC-024-2, R4.	3.00	11.75
PRC-025-1, R1.	2.75	11.5
VAR-001-4.1, R1.	3.00	11.25
VAR-001-4.1, R2.	3.00	11.25
VAR-001-4.1, R3.	3.00	11.5
VAR-001-4.1, R4.	3.00	11
VAR-001-4.1, R5.	3.00	11.75
VAR-001-4.1, R6.	2.75	11.75
VAR-002-4, R1.	3.00	11.25
VAR-002-4, R2.	3.00	12
VAR-002-4, R3.	3.00	12
VAR-002-4, R4.	3.00	11.5
VAR-002-4, R5.	3.00	12
VAR-002-4, R6.	3.00	11.25

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
1	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 82.61% Approval: 80.73%			
2	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 83.01% Approval: 79.89%			
3	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 88.83% Approval: 95.43%			
4	Project 2008-07	Interpretation Request - EOP-002 - Brookfield_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 89.67% Approval: 76.47%			
5	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_rc	Recirculation Ballot	6/13/2008	6/22/2008	Quorum: 89.36% Approval: 95.21%			
6	Project 2008-09	Request for Interpretation - EOP-001-0 - RECM_in	Initial Ballot	6/19/2008	7/2/2008	Quorum: 84.82% Approval: 85.79%			
7	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.57% Approval: 79.13%			
8	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.98% Approval: 78.31%			
9	Pre-2006	IROL Standard - IRO-010_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.71% Approval: 88.40%			
10	Pre-2006	IROL Standard - IRO-009_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.63% Approval: 89.44%			
11	Pre-2006	IROL Standard - IRO-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.67% Approval: 91.71%			
12	Project 2006-07	ATC et al Standard - MOD-030_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.37% Approval: 56.56%			
13	Project 2006-07	ATC et al Standard - MOD-029_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.67% Approval: 92.62%			
14	Project 2006-07	ATC et al Standard - MOD-028_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.64% Approval: 79.47%			
15	Project 2006-07	ATC et al Standard - MOD-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.27% Approval: 80.44%			
16	Project 2006-07	ATC et al Standard - MOD-001_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.02% Approval: 75.97%			
17	Project 2008-10	Request for Interpretation - CIP-006-1 - Progress Energy_in	Initial Ballot	8/7/2008	8/16/2008	Quorum: 88.18% Approval: 21.52%			
18	Pre-2006	IROL Standard - IRO-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.72% Approval: 89.49%			
19	Pre-2006	IROL Standard - IRO-009_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.68% Approval: 86.53%			
20	Pre-2006	IROL Standard - IRO-010_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.75% Approval: 85.95%			
21	Project 2006-07	ATC et al Standards - MOD-001_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 94.87% Approval: 76.83%			
22	Project 2006-07	ATC et al Standard - MOD-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.15% Approval: 81.49%			
23	Project 2006-07	ATC et al Standard - MOD-028_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.54% Approval: 79.34%			
24	Project 2006-07	ATC et al Standard - MOD-029_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.56% Approval: 92.24%			
25	Project 2006-07	ATC et al Standard - MOD-030_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.24% Approval: 74.26%			
26	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting_in	Initial Ballot	9/9/2008	9/17/2008	Quorum: 85.78% Approval: 90.37%			
27	Project 2006-07	ATC et al Standard - MOD-004_in	Initial Ballot	9/11/2008	9/21/2008	Quorum: 79.26% Approval: 66.29%			
28	Project 2007-14	Permanent Changes to CI Timing Tables_in	Initial Ballot	9/12/2008	9/22/2008	Quorum: 79.74% Approval: 100.00%			
29	Project 2008-07	Request for Interpretation - Brookfield Power - EOP-002_rb	Re-ballot	10/6/2008	10/24/2008	Quorum: 82.61% Approval: 74.67%			
30	Project 2008-13	Request for Interpretation - TOP-002-2 - Orlando Utilities Commission_in	Initial Ballot	10/21/2008	10/30/2008	Quorum: 83.33% Approval: 96.94%			
31	Project 2006-01	Project 2006-01 - PER-005-1_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 90.13% Approval: 82.47%			
32	Project 2006-09	Project 2006-09 - FAC-008-2 - Facility Ratings_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 89.13% Approval: 70.01%			
33	Project 2006-07	ATC et al Standard - MOD-004_rc	Recirculation Ballot	10/28/2008	11/6/2008	Quorum: 91.49% Approval: 83.71%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
34	Project 2006-07	Project 2006-07 (ATC) MOD-030-2_in	Initial Ballot	12/1/2008	12/10/2008	Quorum: 83.77% Approval: 86.51%			
35	Project 2006-09	Project 2006-09 - FAC-008-2 - Facility Ratings_rc	Recirculation Ballot	12/10/2008	12/19/2008	Quorum: 93.04% Approval: 57.37%			
36	Project 2008-13	Request for Interpretation - TOP-002-2 - Orlando Utilities Commission_rc	Recirculation Ballot	12/10/2008	12/19/2008	Quorum: 87.62% Approval: 97.47%			
37	Project 2006-01	Project 2006-01 - PER-005-1_rc	Recirculation Ballot	12/12/2008	12/22/2008	Quorum: 91.48% Approval: 80.63%			
38	Project 2008-15	Request for Interpretation - CIP-006-1a - US Army COE_in	Initial Ballot	1/5/2009	1/14/2009	Quorum: 91.15% Approval: 97.39%			
39	Project 2008-16	TOP-004-2 VSL Revisions_in	Initial Ballot	1/5/2009	1/14/2009	Quorum: 91.20% Approval: 93.93%			
40	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting_rc	Recirculation Ballot	1/6/2009	1/15/2009	Quorum: 91.47% Approval: 91.21%			
41	Project 2006-07	Project 2006-07 (ATC) MOD-030-2_rc	Recirculation Ballot	1/20/2009	1/29/2009	Quorum: 85.86% Approval: 86.39%			
42	Project 2008-16	TOP-004-2 VSL Revisions_rc	Recirculation Ballot	1/28/2009	2/6/2009	Quorum: 92.59% Approval: 96.06%			
43	Project 2008-15	Request for Interpretation - CIP-006-1a - US Army COE_rc	Recirculation Ballot	2/6/2009	2/16/2009	Quorum: 93.81% Approval: 99.12%			
44	Project 2008-09	Interpretation Request - EOP-001 - R1 - RECM_in	Initial Ballot	2/27/2009	3/9/2009	Quorum: 89.67% Approval: 89.03%			
45	Project 2008-18	Project 2008-18 Interpretation-Manitoba Hydro_in	Initial Ballot	3/19/2009	3/30/2009	Quorum: 89.78% Approval: 92.62%			
46	Project 2008-06	Project 2008-06: CIP-002-1-CIP-009-1 Revisions_in	Initial Ballot	4/1/2009	4/10/2009	Quorum: 91.90% Approval: 84.06%			
47	Project 2009-10	Project 2009-10 Interpretation - CMPWG - PRC-005-1 R1_in	Initial Ballot	4/8/2009	4/17/2009	Quorum: 92.70% Approval: 92.71%			
48	Project 2006-03	Project 2006-03 EOP-001_EOP-005_EOP-006 System Restoration and Blackstart_in	Initial Ballot	4/14/2009	4/23/2009	Quorum: 89.81% Approval: 76.63%			
49	Project 2008-06	Project 2008-06: CIP-002-1-CIP-009-1 Revisions_rc	Recirculation Ballot	4/17/2009	4/27/2009	Quorum: 94.37% Approval: 88.32%			
50	Project 2008-18	Project 2008-18 Interpretation-Manitoba Hydro_rc	Recirculation Ballot	4/17/2009	4/27/2009	Quorum: 95.56% Approval: 92.81%			
51	Project 2009-11	Project 2009-11 Interpretation WECC Reliability Coordination Subcommittee IRO-10-1_in	Initial Ballot	4/22/2009	5/1/2009	Quorum: 88.64% Approval: 84.77%			
52	Project 2006-03	Project 2006-03 EOP-001_EOP-005_EOP-006 System Restoration and Blackstart_rc	Recirculation Ballot	5/6/2009	5/18/2009	Quorum: 92.08% Approval: 75.39%			
53	Project 2009-15	Project 2009-15 Interpretation - NYISO - MOD-001-1, MOD-029-1_in	initial Ballot	5/25/2009	6/4/2009	Quorum: 85.13% Approval: 82.10%			
54	Project 2009-11	Project 2009-11 Interpretation WECC Reliability Coordination Subcommittee IRO-10-1_rc	Recirculation Ballot	5/26/2009	6/5/2009	Quorum: 90.45% Approval: 85.76%			
55	Project 2009-14	Project 2009-14 Interpretation - PacifiCorp - TPL-002-0a_in	Initial Ballot	6/1/2009	6/11/2009	Quorum: 87.10% Approval: 95.71%			
56	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716_in	Initial Ballot	6/12/2009	6/22/2009	Quorum: 81.72% Approval: 94.09%			
57	Project 2008-14	Project 2008-14 VSLs for CIP-002-1 through CIP-009-1_in	Initial Ballot	6/15/2009	6/24/2009	Quorum: 87.23% Approval: 83.94%			
58	Project 2008-14	Project 2008-14 VSLs for CIP-002-1 through CIP-009-1_rc	Recirculation Ballot	7/7/2009	7/16/2009	Quorum: 92.77% Approval: 84.96%			
59	Project 2009-15	Project 2009-15 Interpretation - NYISO - MOD-001-1, MOD-029-1_rc	Recirculation Ballot	7/8/2009	7/17/2009	Quorum: 90.26% Approval: 82.25%			
60	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716_rc	Recirculation Ballot	7/10/2009	7/20/2009	Quorum: 87.10% Approval: 96.94%			
61	Project 2009-10	Project 2009-10 Interpretation - CMPWG - PRC-005-1 R1_rc	Recirculation Ballot	7/24/2009	8/6/2009	Quorum: 95.26% Approval: 95.62%			
62	Project 2009-14	Project 2009-14 Interpretation - PacifiCorp - TPL-002-0a_rc	Recirculation Ballot	7/24/2009	8/6/2009	Quorum: 91.24% Approval: 98.85%			
63	Project 2007-23	Project 2007-23 TPL Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 90.46%			
64	Project 2007-23	Project 2007-23 TOP Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.40% Approval: 89.14%			
65	Project 2007-23	Project 2007-23 PRC Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.32% Approval: 88.26%			
66	Project 2007-23	Project 2007-23 IRO Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.16% Approval: 90.15%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
67	Project 2007-23	Project 2007-23 INT, PER, and NUC Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 88.63%			
68	Project 2007-23	Project 2007-23 FAC and MOD Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.64% Approval: 87.63%			
69	Project 2007-23	Project 2007-23 CIP, COM, and VAR Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.50% Approval: 85.78%			
70	Project 2007-23	Project 2007-23 BAL Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.28% Approval: 89.56%			
71	Project 2008-08	Project 2008-08 EOP Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 87.98% Approval: 87.31%			
72	Project 2009-17	Project 2009-17 Interpretation - Y-W Electric and Tri-State - PRC-004-1 and PRC-005-1_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 90.32% Approval: 62.15%			
73	RSDP V7	Reliability Standards Development Procedure - Version 7 - June 2009_rb	Re-ballot	7/27/2009	8/14/2009	Quorum: 84.65% Approval: 74.79%			
74	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-001-1_in	Initial Ballot	8/6/2009	8/17/2009	Quorum: 84.68% Approval: 68.92%			
75	Project 2007-23	Project 2007-23 TPL Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 91.96% Approval: 89.28%			
76	Project 2007-23	Project 2007-23 BAL Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.04% Approval: 89.41%			
77	Project 2007-23	Project 2007-23 CIP, COM, and VAR Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.41% Approval: 84.64%			
78	Project 2007-23	Project 2007-23 FAC and MOD Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.67% Approval: 88.04%			
79	Project 2007-23	Project 2007-23 INT, PER, and NUC Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.17% Approval: 88.73%			
80	Project 2007-23	Project 2007-23 IRO Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 91.96% Approval: 90.77%			
81	Project 2007-23	Project 2007-23 PRC Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.31% Approval: 86.93%			
82	Project 2007-23	Project 2007-23 TOP Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.11% Approval: 88.26%			
83	Project 2008-08	Project 2008-08 EOP Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.70% Approval: 85.80%			
84	Order 706-B	Order 706-B Nuclear Implementation Plan_in	Initial Ballot	8/19/2009	8/28/2009	Quorum: 81.96% Approval: 97.37%			
85	Project 2008-07	Request for Interpretation - Brookfield Power - EOP-002_rc	Recirculation Ballot	8/20/2009	8/31/2009	Quorum: 86.96% Approval: 70.85%			
86	Project 2009-12	Project 2009-12 - Interpretation - PacifiCorp - CIP-005-1_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 84.68% Approval: 80.37%			
87	Project 2009-13	Project 2009-13 - Interpretation - PacifiCorp - CIP-006-1_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 84.92% Approval: 79.04%			
88	Project 2009-18	Project 2009-18 - Withdraw Three Midwest ISO Waivers_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 85.28% Approval: 99.62%			
89	Order 706-B	Order 706-B Nuclear Implementation Plan_rc	Recirculation Ballot	9/1/2009	9/10/2009	Quorum: 87.11% Approval: 97.18%			
90	RSDP V7	Reliability Standards Development Procedure - Version 7 - June 2009_rc	Recirculation Ballot	9/2/2009	9/14/2009	Quorum: 86.31% Approval: 76.09%			
91	Project 2008-06	Project 2008-06 Cyber Security (VRFs and VSLs for Version 2 CIP Standards)_in	Initial Ballot	9/10/2009	9/21/2009	Quorum: 87.45% Approval: 94.18%			
92	Project 2009-16	Project 2009-16 - Interpretation - WECC - CIP-007-1_in	Initial Ballot	9/9/2009	9/21/2009	Quorum: 85.31% Approval: 100.00%			
93	Project 2006-04	Project 2006-04 - Back-up Facilities - EOP-008-1_in	Initial Ballot	9/16/2009	9/28/2009	Quorum: 82.69% Approval: 72.86%			
94	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-001-1_rc	Recirculation Ballot	9/29/2009	10/9/2009	Quorum: 89.92% Approval: 68.31%			
95	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-1 Revised R1 for Progress Energy	Initial Ballot	9/30/2009	10/12/2009	Quorum: 79.92% Approval: 74.47%			
96	Project 2009-12	Project 2009-12 - Interpretation - PacifiCorp - CIP-005-1_rc	Recirculation Ballot	10/16/2009	10/26/2009	Quorum: 86.29% Approval: 83.25%			
97	Project 2008-06	Project 2008-06 Cyber Security (VRFs and VSLs for Version 2 CIP Standards)_rc	Recirculation Ballot	11/2/2009	11/12/2009	Quorum: 88.70% Approval: 94.24%			
98	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 2_in	Initial Ballot	11/5/2009	11/16/2009	Quorum: 85.97% Approval: 98.07%			
99	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response_in	Initial Ballot	11/20/2009	11/30/2009	Quorum: 89.58% Approval: 88.07%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
100	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 1)_in	Initial Ballot	11/19/2009	12/7/2009	Quorum: 85.83% Approval: 58.91%			
101	Project 2009-20	Project 2009-20 - Interpretation - BAL-003-0 - Energy Mark, Inc._in	Initial Ballot	11/20/2009	12/7/2009	Quorum: 87.11% Approval: 93.40%			
102	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response_rc	Recirculation Ballot	12/3/2009	12/14/2009	Quorum: 93.33% Approval: 85.55%			
103	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers_in	Initial Ballot	12/1/2009	12/14/2009	Quorum: 86.13% Approval: 72.11%			
104	Project 2009-13	Project 2009-13 - Interpretation - PacifiCorp - CIP-006-1_rc	Recirculation Ballot	12/11/2009	12/23/2009	Quorum: 90.08% Approval: 78.77%			
105	Project 2009-24	Project 2009-24 - Interpretation - FMPA - EOP-005-1_in	Initial Ballot	1/5/2010	1/15/2010	Quorum: 87.68% Approval: 17.79%			
106	Project 2009-25	Project 2009-25 - Interpretation - BPA - BAL-001-01.a and BAL-002-0_in	Initial Ballot	1/5/2010	1/15/2010	Quorum: 88.00% Approval: 34.28%			
107	Project 2009-26	Project 2009-26 - Interpretation - WECC - CIP-004-1_in	Initial Ballot	1/6/2010	1/19/2010	Quorum: 84.21% Approval: 42.24%			
108	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-2	Initial Ballot	1/12/2010	1/22/2010	Quorum: 89.16% Approval: 75.16%			
109	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for FMPAA_in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 84.98% Approval: 90.82%			
110	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 87.36% Approval: 91.79%			
111	Project 2009-29	Project 2009-29 - Interpretation - TOP-002-2a for FMPP_in	Initial Ballot	2/11/2010	2/22/2010	Quorum: 84.34% Approval: 84.56%			
112	Project 2009-19	Project 2009-19 - Interpretation - BAL-002-0 Northwest Power Pool RSG_in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.83% Approval: 48.60%			
113	Project 2009-20	Project 2009-20 - Interpretation - BAL-003-0 - Energy Mark, Inc._rc	Recirculation Ballot	2/16/2010	2/26/2010	Quorum: 92.44% Approval: 91.90%			
114	Project 2009-30	Project 2009-30 - Interpretation - PRC-001-1 for WPSC_in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.51% Approval: 48.74%			
115	Project 2006-02	Project 2006-02 - Assess Transmission Future Needs - TPL-001-1_in	Initial Ballot	2/19/2010	3/1/2010	Quorum: 91.38% Approval: 35.36%			
116	Project 2009-31	Project 2009-31 - Interpretation - TOP-001-1 for FMPP_in	Initial Ballot	3/3/2010	3/16/2010	Quorum: 88.24% Approval: 98.27%			
117	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-2	Recirculation Ballot	3/8/2010	3/18/2010	Quorum: 93.71% Approval: 78.15%			
118	Project 2009-32	Project 2009-32 - Interpretation - EOP-003-1 for FMPP_rb	Re-ballot	3/10/2010	3/31/2010	Quorum: 91.37% Approval: 77.66%			
119	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers (Revision 1)_in	Initial Ballot	3/29/2010	4/8/2010	Quorum: 88.52% Approval: 63.43%			
120	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 3_in	Initial Ballot	4/15/2010	4/26/2010	Quorum: 81.97% Approval: 98.64%			
121	SPM	Standards Process Manual Revisions_in	Initial Ballot	4/19/2010	4/29/2010	Quorum: 87.82% Approval: 80.48%			
122	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 2)_in	Initial Ballot	4/28/2010	5/10/2010	Quorum: 83.15% Approval: 74.55%			
123	SPM	Standards Process Manual Revisions_rc	Recirculation Ballot	4/30/2010	5/10/2010	Quorum: 93.73% Approval: 86.69%			
124	Project 2010-11	Project 2010-11 SAR for TPL Table 1 Order_in	Initial Ballot	5/17/2010	5/27/2010	Quorum: 84.41% Approval: 63.75%			
125	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_in	Initial Ballot	5/19/2010	6/1/2010	Quorum: 84.83% Approval: 90.83%			
126	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_rc	Recirculation Ballot	6/22/2010	7/2/2010	Quorum: 89.10% Approval: 87.24%			
127	Project 2006-04	Project 2006-04 - Backup Facilities - Revision 1_in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 89.05% Approval: 79.45%			
128	Project 2006-08	Project 2006-08 - Reliability Coordination - Transmission Loading Relief_in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 87.04% Approval: 84.98%			
129	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Initial Ballot	7/7/2010	7/17/2010	Quorum: 86.94% Approval: 43.13%			
130	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Initial Ballot	7/8/2010	7/17/2010	Quorum:91.12 % Approval: 22.91%			
131	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Non-binding Poll	7/8/2010	7/17/2010	Quorum: 86.00% Approval: 28.00%			
132	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: Protection System definition	Initial Ballot	7/8/2010	7/17/2010	Quorum: 87.85% Approval: 39.35%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
133	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Initial Ballot	7/9/2010	7/19/2010	Quorum: 86.18% Approval: 65.93%			
134	Project 2006-04	Prokect 2006-04 - Backup Facilities - Revision 1_rc	Recirculation Ballot	7/16/2010	7/26/2010	Quorum: 93.43% Approval: 85.22%			
135	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Successive Ballot	7/23/2010	8/2/2010	Quorum: 94.70% Approval: 58.61%			
136	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Successive Ballot	7/24/2010	8/3/2010	Quorum: 92.99% Approval: 49.61%			
137	Project 2006-08	Project 2006-08 - Reliability Coordination - Transmission Loading Relief_rc	Recirculation Ballot	8/20/2010	8/30/2010	Quorum: 88.26% Approval: 93.93%			
138	Project 2007-04	Project 2007-04 - Certifying System Operators: PER-003-1	Initial Ballot	9/14/2010	9/24/2010	Quorum: 92.73% Approval: 79.17%			
139	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3	Initial Ballot	9/17/2010	9/27/2010	Quorum: 96.46% Approval: 21.77%			
140	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Successive Ballot	9/24/2010	10/4/2010	Quorum: 85.71% Approval: 81.72%			
141	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Successive Ballot	10/2/2010	10/14/2010	Quorum: 84.11% Approval: 84.52%			
142	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 3_rc	Recirculation Ballot	10/4/2010	10/14/2010	Quorum: 88.11% Approval: 99.14%			
143	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_rc	Recirculation Ballot	10/5/2010	10/15/2010	Quorum: 92.19% Approval: 94.78%			
144	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for FMPAA_rc	Recirculation Ballot	10/6/2010	10/16/2010	Quorum: 91.21% Approval: 93.44%			
145	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Recirculation Ballot	10/18/2010	10/28/2010	Quorum: 89.84% Approval: 84.67%			
146	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_in	Initial Ballot	10/20/2010	11/3/2010	Quorum: 93.66% Approval: 43.33%			
147	Project 2010-10	Project 2010-10 FAC-013-2 Planning Transfer Capability_in	Initial Ballot	10/20/2010	11/3/2010	Quorum: 88.54% Approval: 39.85%			
148	2010 SPM	2010 Standard Processes Manual (Proposed Changes)_in	Initial Ballot	10/28/2010	11/7/2010	Quorum: 81.61% Approval: 93.72%			
149	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Recirculation Ballot	11/1/2010	11/11/2010	Quorum: 89.41% Approval: 86.83%			
150	2010 SPM	2010 Standard Processes Manual (Proposed Changes)_rc	Recirculation Ballot	11/9/2010	11/13/2010	Quorum: 87.00% Approval: 92.88%			
151	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 2)_rc	Recirculation Ballot	11/19/2010	12/3/2010	Quorum: 87.81% Approval: 82.41%			
152	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_sb_in	Initial Ballot	12/1/2010	12/10/2010	Quorum: 87.07% Approval: 77.06%			
153	Project 2010-15	Project 2010-15 - Expedited Action Revisions to CIP-005-3	Initial Ballot	12/2/2010	12/11/2010	Quorum: 84.46% Approval: 42.89%			
154	Project 2007-04	Project 2007-04 - Certifying System Operators: PER-003-1	Recirculation Ballot	12/2/2010	12/13/2010	Quorum: 95.50% Approval: 86.91%			
155	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Initial Ballot	12/7/2010	12/16/2010	Quorum: 88.00% Approval: 51.51%			
156	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Successive Ballot	12/10/2010	12/20/2010	Quorum: 79.88% Approval: 44.65%			
157	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Non-binding Poll	12/10/2010	12/20/2010	Quorum: 78.00% Approval: 53.00%			
158	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_sb_rc	Recirculation Ballot	12/20/2010	12/30/2010	Quorum: 90.49% Approval: 80.56%			
159	Project 2010-11	Project 2010-11 TPL Table 1 Footnote B SAR_in	Recirculation Ballot	12/27/2010	1/5/2011	Quorum: 90.42% Approval: 83.33%			
160	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.62% Approval: 22.09%	Oppose 12/16/11		
161	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.62% Approval: 33.49%	Oppose 12/16/11		
162	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.60% Approval: 26.82%	Oppose 12/16/11		
163	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.60% Approval: 28.04%	Oppose 12/16/11		
164	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 29.60%	Oppose 12/16/11		
165	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 24.15%	Oppose 12/16/11		

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166	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 94.02% Approval: 34.30%	Oppose 12/16/11		
167	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 27.28%	Oppose 12/16/11		
168	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 26.61%	Oppose 12/16/11		
169	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 29.88%	Oppose 12/16/11		
170	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Initial Ballot	12/16/2011	1/6/2011	Quorum: 92.15% Approval: 42.06%	Oppose 12/16/11		
171	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Initial Ballot	12/16/2011	1/6/2011	Quorum: 92.56% Approval: 25.34%	Oppose 12/16/11		
172	Project 2010-10	Project 2010-10: FAC Order 729_in	Initial Ballot	12/30/2010	1/8/2011	Quorum: 83.23% Approval: 58.16%			
173	Project 2010-10	Project 2010-10: FAC Order 729_rc	Recirculation Ballot	1/14/2011	1/23/2011	Quorum: 86.65% Approval: 68.98%			
174	Project 2010-11	Project 2010-11 TPL Table 1 Footnote B SAR_rc	Recirculation Ballot	1/26/2011	2/5/2011	Quorum: 93.29% Approval: 86.79%	Support 1/5/11		
175	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Successive Ballot	1/24/2011	2/14/2011	Quorum: 83.95% Approval: 65.71%	Support 2/11/11		
176	Project 2007-23	Project 2007-23 - Violation Severity Levels	Non-binding Poll	2/9/2011	2/22/2011	Quorum: 78.00% Approval: 72.00%	Support 10/28/10		
177	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Successive Ballot	2/18/2011	2/28/2011	Quorum: 79.28% Approval: 79.34%	Support 2/22/11		
178	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Recirculation Ballot	2/24/2011	3/6/2011	Quorum: 87.35% Approval: 68.83%	Support 2/11/11		
179	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	Initial Ballot	2/25/2011	3/7/2011	Quorum: 87.10% Approval: 49.54%	Support 3/2/11		
180	Project 2010-15	Project 2010-15 - Expedited Action Revisions to CIP-005-4	Successive Ballot	4/19/2011	4/28/2011	Quorum: 79.66% Approval: 38.00%	Oppose 4/19/11		
181	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Initial Ballot	4/21/2011	5/2/2011	Quorum: 86.01% Approval: 48.74%	Abstain 4/26/11		
182	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Non-binding Poll	4/21/2011	5/2/2011	Quorum: 75.58% Approval: 73.00%			
183	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Successive Ballot	5/3/2011	5/12/2011	Quorum: 78.33% Approval: 67.00%	No Recommendation		
184	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Non-binding Poll	5/3/2011	5/12/2011	Quorum: 75.00% Approval: 66.00%			
185	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Recirculation Ballot	5/12/2011	5/23/2011	Quorum: 91.25% Approval: 78.92%	Support 5/12/11		
186	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Successive Ballot	5/18/2011	5/31/2011	Quorum: 92.07% Approval: 73.99%			
187	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Non-binding Poll	5/18/2011	5/31/2011	Quorum: 86.79% Approval: 71.9%			
188	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2, TOP-002-2 and TOP-003-2	Initial Ballot	5/31/2011	6/9/2011	Quorum: 88.47% Approval: 48.64%	Oppose 5/31/11		
189	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2, TOP-002-2 and TOP-003-2	Non-binding Poll	5/31/2011	6/9/2011	Quorum: 84.18% Approval: 41.00%			
190	Project 2007-17	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Recirculation Ballot	6/20/2011	6/30/2011	Quorum: 82.97% Approval: 64.76%	Support 6/28/11		
191	Project 2007-17	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Non-binding Poll	6/20/2011	6/30/2011	Quorum: 52.63% Approval: 60.00%			
192	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	Recirculation Ballot	7/13/2011	7/22/2011	Quorum: 94.33% Approval: 75.37%			
193	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-002-3	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 76.99%	Support 7/22/11		
194	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-005-4	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 75.17%	Support 7/22/11		
195	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-014-2	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 76.27%	Support 7/22/11		
196	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-002-3	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.37% Approval: 93.00%			
197	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-005-4	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.66% Approval: 93.00%			
198	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-014-2	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.37% Approval: 89.00%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
199	Project 2007-09	Project 2007-09 – Generator Verification: MOD-026-1	Initial Ballot	7/22/2011	8/1/2011	Quorum: 90.25% Approval: 46.53%	No Consensus 7/28/11		
200	Project 2007-09	Project 2007-09 – Generator Verification: MOD-026-1	Non-binding Poll	7/22/2011	8/1/2011	Quorum: 88.75% Approval: 56.00%			
201	Project 2007-09	Project 2007-09 – Generator Verification: PRC-024-1	Initial Ballot	7/22/2011	8/1/2011	Quorum: 90.82% Approval: 18.23%	No Consensus 7/28/11		
202	Project 2007-09	Project 2007-09 – Generator Verification: PRC-024-1	Non-binding Poll	7/22/2011	8/1/2011	Quorum: 88.35% Approval: 20.79%			
203	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Initial Ballot	9/19/2011	9/29/2011	Quorum: 84.86% Approval: 61.10%	Support 9/21/11		
204	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Non-binding Poll	9/19/2011	9/29/2011	Quorum: 83.13% Approval: 68.68%			
205	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Definition of BES	Initial Ballot	9/30/2011	10/10/2011	Quorum: 92.97% Approval: 71.68%	No Consensus 10/3/11		
206	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Detailed Information to Support BES Exceptions Request	Initial Ballot	9/30/2011	10/10/2011	Quorum: 89.53% Approval: 64.03%	No Consensus 10/7/111		
207	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Recirculation Ballot	10/4/2011	10/13/2011	Quorum: 87.17% Approval: 86.25%	Support 2/22/11		
208	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Initial Ballot	11/7/2011	11/16/2011	Quorum: 88.05% Approval: 85.53%	Support 11/8/11		
209	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Initial Ballot	11/8/2011	11/17/2011	Quorum: 91.20% Approval: 95.05%	Support 11/8/11		
210	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Initial Ballot	11/9/2011	11/18/2011	Quorum: 88.22% Approval: 86.94%	Support 11/10/11		
211	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Initial Ballot	11/9/2011	11/18/2011	Quorum: 85.08% Approval: 85.71%	Support 11/10/11		
212	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Initial Ballot	11/9/2011	11/18/2011	Quorum: 84.82% Approval: 85.31%	Support 11/10/11		
213	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-004-2.1	Initial Ballot	11/9/2011	11/18/2011	Quorum: 84.29% Approval: 96.09%	Support 11/10/11		
214	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-x R1 for Progress Energy	Successive Ballot	11/11/2011	11/21/2011	Quorum: 83.53% Approval: 95.99%	Support 11/14/11		
215	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System and Implementation Plan	Recirculation Ballot	11/10/2011	11/21/2011	Quorum: 95.92% Approval: 81.32%	Support 10/3/11		
216	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Detailed Information to Support BES Exceptions Request	Recirculation Ballot	11/10/2011	11/21/2011	Quorum: 93.02% Approval: 81.48%	Support 10/3/11		
217	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Initial Ballot	11/30/2011	12/9/2011	Quorum: 93.92% Approval: 30.82%	Oppose 12/5/11		
218	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Non-binding Poll	11/30/2011	12/9/2011	Quorum: 89.49% Approval: 36.00%			
219	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Initial Ballot	12/2/2011	12/12/2011	Quorum: 87.97% Approval: 36.21%	Oppose 12/5/11		
220	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	12/2/2011	12/12/2011	Quorum: 85.28% Approval: 45.00%			
221	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-x R1 for Progress Energy	Recirculation Ballot	12/9/2011	12/19/2011	Quorum: 88.02% Approval: 96.04%	Support 11/14/11		
222	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Recirculation Ballot	12/12/2011	12/22/2011	Quorum: 90.10% Approval: 92.49%	Support 11/8/11		
223	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 92.00% Approval: 94.58%	Support 11/8/11		
224	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 88.48% Approval: 90.10%	Support 11/10/11		
225	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 87.17% Approval: 85.38%	Support 11/10/11		
226	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 86.91% Approval: 85.03%	Support 11/10/11		
227	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-004-2.1a	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 86.65% Approval: 96.43%	Support 11/10/11		
228	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 59.93%	Oppose 1/9/12		
229	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 77.08 %	Support 1/9/12		
230	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 78.95%	Support 1/9/12		
231	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Non-binding Poll	1/4/2012	1/13/2012	Quorum: 78.27% Approval: 93.00%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
232	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Non-binding Poll	1/9/2012	1/18/2012	Quorum: 76.41% Approval: 71.42%			
233	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Non-binding Poll	1/9/2012	1/19/2012	Quorum: 81.50% Approval: 67.61%			
234	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Non-binding Poll	1/9/2012	1/19/2012	Quorum: 81.50% Approval: 70.28%			
235	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Successive Ballot	1/30/2012	2/9/2012	Quorum: 81.82% Approval: 54.64%	Oppose 2/7/12		
236	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Successive Ballot	1/30/2012	2/9/2012	Quorum: 82.11% Approval: 80.62%	Support 2/7/12		
237	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Successive Ballot	1/30/2012	2/9/2012	Quorum: 81.82% Approval: 80.21%	Support 2/7/12		
238	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 80.35% Approval: 71.35%			
239	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 80.06% Approval: 90.86%			
240	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 79.77% Approval: 84.69%			
241	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Successive Ballot	3/14/2012	3/23/2012	Quorum: 88.55% Approval: 79.61%	Support 3/16/12		
242	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Initial Ballot	3/14/2012	3/23/2012	Quorum: 89.63% Approval: 94.71%	Support 3/16/12		
243	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR-002 for Constellation	Initial Ballot	3/14/2012	3/23/2012	Quorum: 86.92% Approval: 63.09%	Support 3/16/12		
244	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Successive Ballot	3/19/2012	3/29/2012	Quorum: 81.45% Approval: 61.21%			
245	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Successive Ballot	3/19/2012	3/29/2012	Quorum: 80.38% Approval: 41.09%			
246	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	3/19/2012	3/29/2012	Quorum: 84.32% Approval: 73.93%	Support 3/19/12		
247	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Non-binding Poll	3/19/2012	3/29/2012	Quorum: 81.93% Approval: 66.12%			
248	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Successive Ballot	3/30/2012	4/9/2012	Quorum: 80.37% Approval: 85.18%	Support 4/5/12		
249	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Successive Ballot	3/30/2012	4/9/2012	Quorum: 80.10% Approval: 85.01%	Support 4/5/12		
250	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.28% Approval: 41.09%	Oppose 4/16/12		
251	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.04% Approval: 36.84%	Oppose 4/16/12		
252	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.04% Approval: 48.70%%	Oppose 4/16/12		
253	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.82% Approval: 43.72%			
254	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.04% Approval: 38.56%			
255	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.53% Approval: 46.38%			
256	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1a	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.95% Approval: 92.41%	Support 4/16/12		
257	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28%% Approval: 75.44%			
258	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.02% Approval: 87.22%			
259	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28% Approval: 80.11%			
260	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.21% Approval: 69.84%			
261	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.48% Approval: 67.64%			
262	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 90.96% Approval: 80.08%	Support 3/16/12		
263	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 92.68% Approval: 94.61%	Support 3/16/12		
264	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.72% Approval: 87.34%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
265	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.94% Approval: 87.32%			
266	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1b	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 90.44% Approval: 93.23%			
267	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 76.84%	Abstain 4/19/12		
268	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 88.11%	Support 4/19/12		
269	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 80.79%	Support 4/19/12		
270	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.63% Approval: 37.37%	Abstain 5/17/12		
271	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.45% Approval: 60.55%	Abstain 5/17/12		
272	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.40% Approval: 38.81%	Abstain 5/17/12		
273	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.98% Approval: 55.08%	Abstain 5/17/12		
274	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.22% Approval: 38.50%	Abstain 5/17/12		
275	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.01% Approval: 45.78%	Abstain 5/17/12		
276	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.19% Approval: 67.19%	Abstain 5/17/12		
277	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.01% Approval: 60.19%	Abstain 5/17/12		
278	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.39% Approval: 47.92%	Abstain 5/17/12		
279	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.39% Approval: 58.23%	Abstain 5/17/12		
280	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Successive Ballot	5/11/2012	5/21/2012	Quorum: 85.12% Approval: 66.23%	Abstain 5/17/12		
281	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Successive Ballot	5/11/2012	5/21/2012	Quorum: 84.09% Approval: 47.88%	Abstain 5/17/12		
282	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	5/15/2012	5/24/2012	Quorum: 84.43% Approval: 46.18%			
283	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	5/15/2012	5/24/2012	Quorum: 79.95% Approval: 52.67%			
284	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Initial Ballot	6/11/2012	6/20/2012	Quorum: 84.14% Approval: 21.11%	Oppose 6/13/12		
285	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	6/11/2012	6/20/2012	Quorum: 81.01% Approval: 28.30%			
286	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	6/18/2012	6/27/2012	Quorum: 79.46% Approval: 79.00%			
287	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Non-binding Poll	6/18/2012	6/27/2012	Quorum: 75.00% Approval: 70.21%			
288	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Successive Ballot	6/18/2012	6/27/2012	Quorum: 85.98% Approval: 68.22%	Support 6/26/12		
289	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Initial Ballot	6/26/2012	7/5/2012	Quorum: 84.24% Approval: 23.82%	Oppose 6/27/12		
290	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	6/26/2012	7/5/2012	Quorum: 82.26% Approval: 25.19%			
291	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.34% Approval: 81.71%			
292	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.04% Approval: 81.72%			
293	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 84.16% Approval: 79.16%			
294	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 83.87% Approval: 86.91%			
295	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Successive Ballot	6/27/2012	7/9/2012	Quorum: 75.37% Approval: 72.16%	No Consensus 7/5/12		
296	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Non-binding Poll	6/27/2012	7/11/2012	Quorum: 75.37% Approval: 73.71%			
297	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Recirculation Ballot	7/18/2012	7/27/2012	Quorum: 90.97% Approval: 69.81%	Support 6/26/12		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
298	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Non-binding Poll	7/18/2012	7/27/2012	Quorum: 81.31% Approval: 60.93%			
299	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Initial Ballot	7/20/2012	7/30/2012	Quorum: 80.39% Approval: 79.28%	Oppose 7/20/12		
300	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Non-binding Poll	7/20/2012	7/30/2012	Quorum: 78.26% Approval: 76.07%			
301	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Initial Ballot	7/24/2012	8/2/2012	Quorum: 83.11% Approval: 54.16%	Oppose 7/20/12		
302	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	8/17/2012	8/27/2012	Quorum: 78.11% Approval: 80.31%	Support 6/22/12		
303	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group	Successive Ballot	8/23/2012	9/4/2012	Quorum: 79.21% Approval: 87.78%	Support 2/22/10		
304	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Initial Ballot	8/29/2012	9/7/2012	Quorum: 86.71% Approval: 37.68%	Support 9/5/12		
305	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	8/29/2012	9/7/2012	Quorum: 84.17% Approval: 37.36%			
306	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Recirculation Ballot	9/6/2012	9/17/2012	Quorum: 80.35% Approval: 75.01%			
307	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols	Successive Ballot	9/11/2012	9/20/2012	Quorum: 77.70% Approval: 50.57%	Support 9/15/12		
308	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	9/11/2012	9/20/2012	Quorum: 84.05% Approval: 54.07%			
309	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Recirculation Ballot	9/12/2012	9/21/2012	Quorum: 85.36% Approval: 87.34%			
310	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	9/18/2012	9/27/2012	Quorum: 78.54% Approval: 63.40%	No Consensus 9/27/12		
311	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	9/18/2012	9/27/2012	Quorum: 78.93% Approval: 71.04%			
312	Project 2009-19	Project 2009-19 - Interpretation of BAL-002-0 NWPP Reserve Sharing Group	Recirculation Ballot	9/28/2012	10/8/2012	Quorum: 85.11% Approval: 90.34%	Support 2/22/10		
313	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 74.85%	Support 10/4/12		
314	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.37% Approval: 89.50%	Support 10/4/12		
315	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 85.58%	Support 10/4/12		
316	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 89.46%	Support 10/4/12		
317	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.11%	Support 10/4/12		
318	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 87.73%	Support 10/4/12		
319	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.74%	Support 10/4/12		
320	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.73%	Support 10/4/12		
321	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 84.60%	Support 10/4/12		
322	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.90%	Support 10/4/12		
323	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Successive Ballot	10/1/2012	10/10/2012	Quorum: 78.93% Approval: 94.00%	Support 10/4/12		
324	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Successive Ballot	10/1/2012	10/10/2012	Quorum: 79.13% Approval: 91.59%	Support 10/4/12		
325	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Initial Ballot	10/3/2012	10/12/2012	Quorum: 87.50% Approval: 63.25%	Support 10/4/12		
326	VRFs and VSLs	Revisions to Outstanding VRFs and VSLs	Non-binding Poll	10/10/2012	10/23/2012	Quorum: 78.57% Approval: 73.02%			
327	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Recirculation Ballot	10/15/2012	10/24/2012	Quorum: 81.08% Approval: 80.51%	Support 6/22/12		
328	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.55% Approval: 76.50%			
329	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.00% Approval: 57.24%			
330	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Successive Ballot	10/19/2012	10/31/2012	Quorum: 83.61% Approval: 68.31%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
331	Project 2007-09	Project 2007-09_Generator Verification: MOD-027-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.34% Approval: 71.53%			
332	Project 2007-09	Project 2007-09_Generator Verification: PRC-019-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.07% Approval: 70.64%			
333	Project 2007-09	Project 2007-09_Generator Verification: MOD-026-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.88% Approval: 77.10%			
334	Project 2007-09	Project 2007-09_Generator Verification: PRC-024-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.40% Approval: 52.72%			
335	Project 2007-09	Project 2007-09_Generator Verification: MOD-025-2	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 77.94% Approval: 64.24%			
336	Project 2007-09	Project 2007-09_Generator Verification: MOD-027-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.06% Approval: 68.93%			
337	Project 2007-09	Project 2007-09_Generator Verification: PRC-019-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.51% Approval: 63.63%			
338	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 78.59%	Support 10/4/12		
339	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 92.75%	Support 10/4/12		
340	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 89.73%	Support 10/4/12		
341	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 93.73%	Support 10/4/12		
342	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.53%	Support 10/4/12		
343	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 91.79%	Support 10/4/12		
344	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.47%	Support 10/4/12		
345	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 94.60%	Support 10/4/12		
346	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 88.99%	Support 10/4/12		
347	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.67%	Support 10/4/12		
348	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation Plan	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 94.91%	Support 10/4/12		
349	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 93.23%	Support 10/4/12		
350	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Recirculation Ballot	10/24/2012	11/5/2012	Quorum: 85.14% Approval: 71.39%			
351	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	10/24/2012	11/5/2012	Quorum: 78.93% Approval: 71.04%			
352	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Successive Ballot	10/26/2012	11/6/2012	Quorum: 82.04% Approval: 76.08%	Support 11/5/12		
353	Project 2010-11	Project 2010-11 TPL footnote b Initial Ballot October 2012 in	Initial Ballot	11/9/2012	11/19/2012	Quorum: 80.45% Approval: 56.18%			
354	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Initial Ballot	11/26/2012	12/5/2012	Quorum: 84.81% Approval: 72.57%	Oppose 12/5/12		
355	Project 2013-02	Project 2013-02 - Paragraph 81	Initial Ballot	11/30/2012	12/10/2012	Quorum: 75.77% Approval: 96.45%	Support 12/10/12		
356	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	12/4/2012	12/13/2012	Quorum: 76.78% Approval: 53.57%	No Consensus 12/13/12		
357	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	12/4/2012	12/13/2012	Quorum: 77.22% Approval: 57.91%			
358	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Successive Ballot	12/7/2012	12/17/2012	Quorum: 76.47% Approval: 33.23%	Oppose 12/17/12		
359	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	12/7/2012	12/17/2012	Quorum: 75.58% Approval: 34.80%			
360	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Initial Ballot	12/11/2012	12/20/2012	Quorum: 84.50% Approval: 95.60%	Support 12/19/12		
361	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Successive Ballot	12/11/2012	12/20/2012	Quorum: 83.24% Approval: 84.48%	Support 12/19/12		
362	Project 2007-09	Project 2007-09_Generator Verification: MOD-025-2	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.89% Approval: 73.06%			
363	Project 2007-09	Project 2007-09_Generator Verification: MOD-026-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 79.00% Approval: 79.36%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
364	Project 2007-09	Project 2007-09_Generator Verification: MOD-027-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.68% Approval: 74.27%			
365	Project 2007-09	Project 2007-09_Generator Verification: PRC-019-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 85.87% Approval: 73.63%			
366	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.19% Approval: 76.53%			
367	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	1/2/2013	1/11/2013	Quorum: 78.16% Approval: 60.31%	Support 1/11/13		
368	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	Non-binding Poll	1/2/2013	1/11/2013	Quorum: 76.38% Approval: 55.68%			
369	Project 2010-11	Project 2010-11 Successive Ballot December 2012_in	Successive Ballot	1/2/2013	1/11/2013	Quorum: 85.47% Approval: 65.77%	No Consensus 1/11/13		
370	Project 2010-14.1	Project 2010-14.1_- Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Initial Ballot	1/4/2013	1/14/2013	Quorum: 83.94% Approval: 21.80%	Oppose 1/11/13		
371	Project 2010-14.1	Project 2010-14.1_- Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Non-binding Poll	1/4/2013	1/14/2013	Quorum: 82.23% Approval: 24.27%			
372	Project 2013-02	Project 2013-02 - Paragraph 81	Recirculation Ballot	1/8/2013	1/17/2013	Quorum: 84.60% Approval: 95.22%	Support 12/10/12		
373	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Recirculation Ballot	1/14/2013	1/23/2013	Quorum: 87.13% Approval: 99.09%	Support 12/19/12		
374	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Recirculation Ballot	1/18/2013	1/28/2013	Quorum: 85.90% Approval: 85.57%	Support 12/19/12		
375	Project 2010-11	Project 2010-11 Recirculation Ballot Jan 2013_in	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 88.55% Approval: 69.63%	No Consensus 1/11/13		
376	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 85.67% Approval: 77.61%	Oppose 12/5/12		
377	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Successive Ballot	2/11/2013	2/20/2013	Quorum: 77.62% Approval: 50.66%	Support 9/5/12		
378	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	2/11/2013	2/20/2013	Quorum: 75.38% Approval: 50.60%			
379	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	2/15/2013	2/28/2013	Quorum: 78.80% Approval: 89.01%	Support 1/11/13		
380	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Non-binding Poll	2/15/2013	2/28/2013	Quorum: 76.38% Approval: 84.24%			
381	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Initial Ballot	3/1/2013	3/11/2013	Quorum: 76.36% Approval: 54.65%			
382	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Successive Ballot	3/13/2013	3/22/2013	Quorum: 77.48% Approval: 84.27%	No Consensus 3/22/13		NPCC to abstain - international nature of the ERO and BPS is not used in Reliability Standards
383	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.58% Approval: 97.18%	Support 3/14/13		
384	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.52% Approval: 98.89%	Support 3/14/13		
385	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Recirculation Ballot	3/18/2013	3/27/2013	Quorum: 81.33% Approval: 89.44%	Support 1/11/13		

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386	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	3/27/2013	4/5/2013	Quorum: 78.39% Approval: 57.50%	No Consensus 4/4/13		The RSC did not reach a full consensus however the majority of respondents had indicated they will support the standard - see comment form for further details. Some believe the standard is not necessary and that existing whitepapers alleviate the need for it. In recognition of the NERC BOT's expectations that COM-003 will be approved by the industry and brought before them for approval, NPCC has voted affirmatively and will supply comments for the record outlining our concerns.
387	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	3/27/2013	4/5/2013	Quorum: 77.97% Approval: 54.28%			
388	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.60% Approval: 66.98%	No Consensus 4/23/13		The majority of NPCC's Balancing Authorities have indicated support for the standard, however NPCC as the Regional Entity has concerns based on results of the field trials that were conducted. These field trials have indicated the potential for an increased number of SOL violations as well as potential for increased ACE due to large inadvertent flows with the proposed BAAL limits based on frequency triggers. To be respectful of the positions of the NPCC BAs who will have to implement this new methodology and the support expressed, NPCC as the Regional Entity will cast an Abstention
389	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 42.75%	Oppose 4/23/13		There is a lack of technical justification for the 500 MW threshold within the standard-NPCC will submit suggested improvements

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
390	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 23.84%	Oppose 4/23/13		Losses of large blocks of load are typically caused by coincident transmission contingencies. Excessive and uninformed adjustments made to generation in order to bring the ACE to zero may well lead to further transmission issues. NPCC will submit suggested improvements
391	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
392	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
393	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
394	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Recirculation Ballot	4/18/2013	4/29/2013	Quorum: 80.70% Approval: 88.15%	No Consensus 3/22/13		
395	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Successive ballot	5/15/2013	5/24/2013	Quorum: 81.25% Approval: 69.23%	Support 5/23/13		The Regional Standard Committee has not expressed any concerns of significance that would warrant a ballot to reject, therefore the RSC recommends a yes vote, "Affirmative", to accept the standard
396	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Non-binding Poll	5/15/2013	5/24/2013	Quorum: 80.17% Approval: 61.11%			
397	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Successive Ballot	6/24/2013	7/3/2013	Quorum: 77.65% Approval: 52.71%			
398	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Non-binding Poll	6/24/2013	7/3/2013	Quorum: 77.12% Approval: 52.48%			
399	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Initial Ballot	7/3/2013	7/12/2013	Quorum: 85.53% Approval: 49.73%			
400	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Successive Ballot	7/10/2013	7/19/2013	Quorum: 76.32% Approval: 58.36%	No Consensus 7/19/13 [Due to the concerns expressed over the potential actions by the NERC BOT and FERC as well as the incremental improvement of the standard over the previous versions, NPCC as the Regional Entity will support the standard and submit comments.]		organizations support the standard as written however some members expressed concern that in order to measure compliance with R1 and R2, the standard will require all Reliability Directives to be investigated to determine if RC approved and documented communication protocols have been violated. Also it was identified that TO, BA communication protocols would have to approved by the RC potentially causing some legal issues if protocols aren't approved and casts question on the enforcement of those protocols. NPCC will be submitting some helpful comments should the standard pass and some non-substantive revision be performed prior to the "final" (previously named recirculation) ballot.
401	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 76.20% Approval: 55.37%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
402	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Successive Ballot	7/10/2013	7/19/2013	Quorum: 85.05% Approval: 72.43%	Support 7/19/13		
403	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 82.51% Approval: 64.59%			
404	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Final Ballot	7/16/2013	7/25/2013	Quorum: 92.31% Approval: 74.54%	No Consensus 7/22/13		The RSC has not reached a full consensus however the majority are in support. Issues outstanding for those not in support are concern over "hitting limits" more frequently and potential issues with BA's potentially "dragging" on the interconnection. NPCC will be voting affirmative on the standard.
405	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Initial Ballot	7/26/2013	8/5/2013	Quorum: 80.05% Approval: 93.00%	Support 8/5/13		
408	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025-1	Final Ballot	8/2/2013	8/12/2013	Quorum: 89.13% Approval: 76.52%	Support 8/12/13		
406	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Initial Ballot	8/2/2013	8/12/2013	Quorum: 76.32% Approval: 62.74%	Support 8/9/13		
407	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	8/2/2013	8/12/2013	Quorum: 75.89% Approval: 55.45%			
409	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Initial Ballot	8/14/2013	8/23/2013	Quorum: 78.33% Approval: 79.42%	Support 8/23/13		
410	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Non-binding Poll	8/14/2013	8/23/2013	Quorum: 77.45% Approval: 81.37%			
411	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Ballot	8/16/2013	8/26/2013	Quorum: 76.14% Approval: 51.10%	No Consensus 8/26/13		NPCC to support with comments
412	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Non-binding Poll	8/16/2013	8/26/2013	Quorum: 75.98% Approval: 53.29%			
413	Project 2010-01	Project 2010-01 - Training - PER-005-2	Ballot	8/23/2013	9/3/2013	Quorum: 75.25% Approval: 34.46%	No Consensus 8/31/13		NPCC to support with comments The most contentious issues raised by RSC members was surrounding the Control Center definition and the potential to vastly expand those needing training subject to the standard and compliance and that there was no need for a standard, rather, the FERC Directives should be addressed through other means.
414	Project 2010-01	Project 2010-01 - Training - PER-005-2	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 80.45% Approval: 34.24%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
415	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Ballot	8/23/2013	9/3/2013	Quorum: 81.89% Approval: 43.79%	Oppose 8/31/13		The standard, in the view of the group, has extensive issues including but not limited to, applicability issues, lacks clarity, missing measures, quality, and other substantive issues. NPCC will be submitting detailed comments to address these issues. The RSC does not believe it would be beneficial to support the standard at this point as the next step, if it fails the initial ballot, would still require an additional ballot prior to moving to recirculation due to the substantive changes that are needed for the next revision. NPCC will be submitting helpful comments to NERC and supporting the drafting team effort.
416	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 79.95% Approval: 44.23%			
417	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Ballot	8/26/2013	9/4/2013	Quorum: 82.29% Approval: 41.24%	Support 8/31/13		
418	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 79.66% Approval: 40.00%			
419	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Ballot	8/26/2013	9/4/2013	Quorum: 81.96% Approval: 55.76%	Support 8/31/13		
420	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 80.35% Approval: 58.97%			
421	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	8/26/2013	9/4/2013	Quorum: 78.68% Approval: 66.11%	Support 8/31/13		
426	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Final Ballot	9/4/2013	9/13/2013	Quorum: 85.93% Approval: 90.83%	Support 8/5/13		
422	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Ballot	9/6/2013	9/16/2013	Quorum: 76.15% Approval: 58.23%	No Consensus 9/12/13		
423	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Non-binding Poll	9/6/2013	9/16/2013	Quorum: 75.69% Approval: 59.66%			
424	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Final Ballot	9/11/2013	9/20/2013	Quorum: 91.64% Approval: 98.61%	Support 3/14/13		
425	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Final Ballot	9/11/2013	9/20/2013	Quorum: 90.98% Approval: 98.92%	Support 3/14/13		
427	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Additional Ballot	10/9/2013	10/21/2013	Quorum: 77.58% Approval: 88.75%	Support 10/16/13		
428	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	10/9/2013	10/21/2013	Quorum: 75.89% Approval: 90.04%			
429	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Final Ballot	10/16/2013	10/25/2013	Quorum: 85.71% Approval: 85.38%			
430	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	10/18/2013	10/29/2013	Quorum: 75.83% Approval: 72.55%	Support 10/21/13		
431	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Final Ballot	10/25/2013	11/4/2013	Quorum: 86.90% Approval: 91.95%			
432	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	10/25/2013	11/7/2013	Quorum: 76.67% Approval: 58.24%	No Consensus 11/1/13		
433	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	11/1/2013	11/12/2013	Quorum: 76.23% Approval: 56.48%	Support 11/11/13		

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
434	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Initial Ballot	11/4/2013	11/13/2013	Quorum: 76.12% Approval: 67.35%	Support 11/5/13		
435	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-006-4	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 75.58%	Support 11/5/13		
436	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-009-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 68.40%	Support 11/5/13		
437	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 58.03%	Support 11/5/13		
438	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-011-1	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.52% Approval: 71.35%	Support 11/5/13		
439	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Initial Ballot	11/4/2013	11/15/2013	Quorum: 76.42% Approval: 77.82%	Support 11/5/13		
440	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Final Ballot	11/8/2013	11/18/2013	Quorum: 81.68% Approval: 74.34%	Support 10/21/13		
441	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Additional Ballot	11/8/2013	11/20/2013	Quorum: 81.69% Approval: 82.97%	No Consensus 8/26/13		
442	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.05% Approval: 73.46%	Support 8/31/13		
443	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.84% Approval: 69.42%	Support 8/31/13		
444	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	11/13/2013	11/22/2013	Quorum: 80.54% Approval: 57.59%	Support 8/31/13		
445	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Additional Ballot	11/15/2013	11/25/2013	Quorum: 80.81% Approval: 69.43%			
446	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	11/15/2013	11/25/2013	Quorum: 81.06% Approval: 66.09%			
447	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2	Additional Ballot	12/2/2013	12/12/2013	Quorum: 75.29% Approval: 64.24%	No Consensus 12/9/13	Affirmative	
448	Project 2007-11	Project 2007-11 Disturbance Monitoring - PRC-002-2	Initial Ballot	12/6/2013	12/16/2013	Quorum: 82.25% Approval: 43.29%	No Consensus 12/15/13	Affirmative	Highlights of comments received expressed: • Agreement with the methodology to determine BES locations for which data had to be captured • Use of the term "locations" • DDR for Flowgates, IROLs • Clarification needed for some data that is to be captured • Editorial suggestions
449	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Final Ballot	12/6/2013	12/16/2013	Quorum: 87.53% Approval: 77.49%	Support 8/31/13	Affirmative	
450	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-006-4	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 80.77%	Support 11/5/13	Affirmative	
451	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-009-2	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 72.86%	Support 11/5/13	Affirmative	
452	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-011-1	Final Ballot	12/10/2013	12/20/2013	Quorum: 84.78% Approval: 72.91%	Support 11/5/13	Affirmative	
453	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Final Ballot	12/11/2013	12/20/2013	Quorum: 87.16% Approval: 86.40%	No Consensus 8/26/13	Affirmative	
454	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Final Ballot	12/13/2013	12/23/2013	Quorum: 84.34% Approval: 75.35%		Affirmative	
455	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-027-1	Additional Ballot	12/9/2013	12/31/2013	Quorum: 76.60% Approval: 65.71%	No Consensus 12/27/13	Affirmative	
456	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	1/10/2014	1/21/2014	Quorum: 76.92% Approval: 81.41%	Support 8/31/13	Affirmative	
457	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	1/8/2014	1/22/2014	Quorum: 7912% Approval: 74.63%	Support 11/11/13	Affirmative	
458	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 81.19%	Support 11/5/13	Affirmative	
459	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 90.23%	Support 11/5/13	Affirmative	

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	
460	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Additional Ballot	1/16/2014	1/29/2014	Quorum: 76.12% Approval: 92.17%	Support 11/5/13	Affirmative		
461	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	1/22/2014	1/31/2014	Quorum: 76.03% Approval: 71.86%	No Consensus 11/1/13	Affirmative	Ballot Period Extended to 2/4/14	
462	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.88% Approval: 83.44%	Support 11/5/13	Affirmative		
463	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.58% Approval: 91.51%	Support 11/5/13	Affirmative		
464	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Final Ballot	1/27/2014	2/5/2014	Quorum: 82.49% Approval: 82.45%	Support 8/31/13	Affirmative		
465	Project 2010-01	Project 2010-01 - Training - PER-005-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 84.02% Approval: 77.06%	Support 11/11/13	Affirmative		
466	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Final Ballot	1/31/2014	2/10/2014	Quorum: 81.79% Approval: 90.12%	Support 11/5/13	Affirmative		
467	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Additional Ballot	2/21/2014	3/3/2014	Quorum: 75.06% Approval: 62.63%	Support 9/5/12	Affirmative	Ballot Period Extended to 3/11/14	
468	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Final Ballot	3/28/2014	4/7/2014	Quorum: 78.21% Approval: 77.62%	Support 3/28/14	Affirmative		
469	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	4/1/2014	4/10/2014	Quorum: 76.92% Approval: 83.40%	Support 8/31/13	Affirmative		
470	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	4/4/2014	4/14/2014	Quorum: 78.03% Approval: 82.40%		--		
471	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	Initial Ballot	4/20/2014	4/24/2014	Quorum: 88.60% Approval: 82.07%	Support 4/23/14	Abstain		
472	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Final Ballot	4/25/2014	5/5/2014	Quorum: 80.37% Approval: 90.00%	Support--4/25/14	Affirmative		
473	Project 2013-04	Project 2013-04 - Voltage and Reactive Control - VAR-001-4, VAR-002-3	Final Ballot	4/23/2014	5/5/2014	Quorum: 83.84% Approval: 88.26%	Support--4/10/14	Affirmative		
474	Project 2014-04	Project 2014-04 - Physical Security - CIP-014-1	Final Ballot	5/1/2014	5/5/2014	Quorum: 92.53% Approval: 85.61%	Support--4/23/14	Abstain		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Initial Ballot	5/6/2014	5/15/2014	Quorum: 85.79%/79.08% Approval: 86.28%/78.81%	No Consensus--5/15/14	Reject		
476	Project 2012-13	Project 2012-13 - NUC - Nuclear Plant Interface Coordination	Initial Ballot	5/13/2014	5/22/2014	Quorum: 80.60% Approval: 97.36%	Support--5/20/14	Affirmative		
477	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays) - PRC-005-X	Initial Ballot	5/23/2014	6/2/2014	Quorum: 85.42% Approval: 47.89%	Support	Affirmative		
478	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Initial Ballot	5/30/2014	6/9/2014	Quorum: 79.06% Approval: 17.02%	Does not Support--6/6/14	Negative		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Final Ballot	6/12/2014	6/23/2014	Quorum: Approval: 89.03%/83.46%	Support	Affirmative		
479	Project 2007-11	Project 2007-11 - Disturbance Monitoring - PRC-002-2	Additional Ballot	6/13/2014	6/23/2014	Quorum: 77.69% Approval: 52.29%	Support	Affirmative	Extended to achieve a quorum.	Last RSC Meeting
480	Project 2010-05.1	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Additional Ballot	6/20/2014	7/9/2014	Quorum: 76.98% Approval: 74.53%	Support	Affirmative	Extended to achieve a quorum.	
481	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Ballot	6/23/2014	7/2/2014	Quorum: 82.32%/82.59%/82.59%/82.85%/82.85%/82.06%/82.59%/82.85%/82.85%/81.00%/80.74% Approval: 68.57%/36.94%/47.87%/60.26%/61.67%/57.94%/30.99%/62.18%/63.07%/62.64%/64.70%	No Consensus--6/24/14	Affirmative Negative Affirmative Affirmative Affirmative Affirmative Negative Affirmative Affirmative		
482	Project 2012-13	Project 2012-13 NUC - Nuclear Plant Interface Coordination	Final Ballot	6/24/2014	7/3/2014	Quorum: 88.63% Approval: 97.23%	Support--6/23/14	Affirmative		
483	Project 2014-02	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions Rich HTML Content 1	Final Ballot	7/7/2014	7/16/2014	Quorum: 80.73%/80.49%/80.00%/80.24%/80.24%/80.49%/80.24%/78.29%	CIP-003 No CIP-004 Yes CIP-006 Yes CIP-007 Yes CIP-009 Yes			

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
483	Project 2014-02	Rich Hydro Content 1 http://www.nerc.com/pa/Stand/Pages/Project-2014-XX-Critical-Infrastructure-Protection-Version-5-Revisions.aspx	Final Ballot	7/7/2014	7/16/2014	Approval: 35.67%/80.76%/76.24%/78.41%/85.32%/49.42%/82.55%/78.58%	CIP-003 Yes CIP-010 Yes CIP-011 Yes Definitions Yes Support--7/14/14		
484	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Final Ballot	7/16/2014	7/25/2014	Quorum: 78.92% Approval: 58.88%	Support--7/23/14		
485	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	7/18/2014	7/28/2014	Quorum: 79.49%/80.15%/80.00%/80.83%/80.36% Approval: 91.38%/92.20%/89.51%/90.58%/87.09%	Support--7/24/14	Affirmative	
486	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	7/21/2014	7/30/2014	Quorum: 82.67% Approval: 55.77%		Affirmative	
487	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Initial Ballot	7/29/2014	8/7/2014	Quorum: 76.37% Approval: 76.91%		Affirmative	
488	Project 2012-13	Project 2009-03 Emergency Operations	Initial Ballot	8/6/2014	8/15/2014	Quorum: 77.66% Approval: 42.27%	Negative--8/14/14	Negative	
489	Project 2014-01	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Final Ballot	7/29/2014	8/7/2014	Quorum: 77.94% Approval: 79.75%	Support	Affirmative	
490	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	8/27/2014	9/5/2014	Quorum: 85.32%/86.01% Approval: 95.35%/95.86%	Support	Affirmative	
491	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and	Additional Ballot	9/3/2014	9/12/2014	Quorum: 84.33% Approval: 76.03%	Support--9/4/14	Affirmative	
492	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Additional Ballot	9/10/2014	9/19/2014	Quorum: 85.75%/84.96%/84.96%/85.22%/84.96%/85.22%/85.49%/85.22%/86.28%/83.11%/83.91% Approval: 76.12%/74.23%/75.67%/85.49%/75.96%/78.67%/48.73%/78.87%/87.03%/93.34%/90.13%	TOP-001-3: Negative TOP-002-4: Affirmative TOP-003-3: Affirmative IRO-001-4: No consensus however the majority indicated an Affirmative vote IRO-002-4: Negative IRO-008-2: No consensus, a majority indicated a Negative and the others indicated abstention IRO-010-2: Affirmative IRO-014-3: Negative IRO-017-1: Affirmative Implementation Plan and Definitions: Affirmative 9/18/14		
493	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	9/23/2014	10/2/2014	Quorum: 79.94% Approval: 46.73%	Negative--10/1/14		
494	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	9/26/2014	10/6/2014	Quorum: 79.01% Approval: 53.02%	Affirmative--10/1/14		
495	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Additional Ballot	9/29/2014	10/8/2014	Quorum: 83.24%/84.82% Approval: 80.69%/84.05%	Affirmative--10/7/14	Affirmative	
496	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	10/1/2014	10/10/2014	Quorum: 82.93% Approval: 57.95%	Affirmative--10/7/14		
497	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Additional Ballot	10/3/2014	10/14/2014	Quorum: 80.54% Approval: 75.79% Approval:	Affirmative--10/7/14		

RSC Meeting #16-6, Agenda Item 6.3: Comment History

(As of 11/21/2016)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
1.	N/A	Standards Project Prioritization Reference Document and Tool	Project Prioritization Tool		1/21/11	2/10/11	Yes 2/10/11
2.	Project 2007-23	Project 2007-23 - Violation Severity Levels	VSLs		1/20/11	2/18/11	Yes 2/18/11
3.	N/A	CAN-0015--Draft CAN-0015 Unavailability of NERC Tools	CAN-0015 Unavailability of NERC Tools		2/4/11	2/18/11	Yes 2/18/11
4	N/A	CAN-0016--Draft CAN-0016 CIP-001-1 R1 - Applicability to Non-BES	CAN-0016 CIP-001-1, R1		2/4/11	2/18/11	Yes 2/18/11
5.	N/A	CAN-0018--Draft CAN-0018 FAC-008 R.1.2.1 - Terminal Equipment	CAN-0018 FAC-008, R.1.2.1		2/4/11	2/18/11	Yes 2/18/11
6.	Regional Standard	Regional Reliability Standards - PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		1/10/11	2/24/11	
7.	Project 2007-07	Project 2007-07 - Vegetation Management - FAC-003	FAC-003-2		1/27/11	2/28/11	Yes 2/28/11
8.	N/A	CAN-0017--Draft CAN-0017 CIP-007 R5 System Access and Password Controls	CAN-0017 CIP-007, R5		2/11/11	3/4/11	Yes 3/4/11
9.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1		2/4/11	3/7/11	Yes 3/7/11
10.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	COM-001 COM-002 IRO-001 IRO-014		1/18/11	3/7/11	Yes 3/7/11
11.	NERC RoP	Proposed Changes to Rules of Procedure to Add Section 1700 - Challenges to Determinations	RoP Section 1700		2/14/11	3/7/11	Yes 3/7/11
12.	Project 2009-02	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Concept White Paper		2/16/11	4/4/11	Yes 4/4/11
13.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		3/4/11	4/4/11	Yes 4/4/11

RSC Meeting #16-6, Agenda Item 6.3: Comment History

(As of 11/21/2016)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
14.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		3/9/11	4/8/11	Yes 4/8/11
15.	RFC RoP	Notice of Proposed Changes to RFC Rules of Procedure and Request for Comments			3/1/11	4/15/11	
16.	NERC RoP	Proposed Amendments to NERC Rules of Procedure Appendices 3B and 3D	Appendices 3B and 3D		3/1/11	4/15/11	Yes 4/15/11
17.	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	CIP-005		3/29/11	4/28/11	Yes 4/27/11
18.	Project 2009-06	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	FAC-008-3		3/17/11	5/2/11	Yes 5/2/11
19.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		4/13/11	5/12/11	Yes 5/9/11
20.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		4/28/11	5/27/11	Yes 5/27/11
21.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	TPL-001-2		4/18/11	5/31/11	Yes 5/31/11
22.	Project 2007-03	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	TOP-001 through TOP-008 and PER-001		4/26/11	6/9/11	Yes 6/9/11
23.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		5/11/11	6/10/11	Yes 6/10/11
24.	NERC RoP	Rules of Procedure Development Team: BES Definition Exception Process	BES Definition Exception Process		5/11/11	6/10/11	Yes 6/10/11
25.	N/A	CAN-0024--Draft CAN-0024 CIP-002 through CIP-009 Routable Protocols and Data Diodes	CAN-0024 CIP-002 through CIP-009		5/20/11	6/10/11	
26.	N/A	CAN-0029--Draft CAN-0029 PRC-004-1 R1, R2 and R3 Misoperations	CAN-0029 PRC-004-1 R1, R2 and R3		5/20/11	6/10/11	
27.	N/A	CAN-0030--Draft CAN-0030 Attestations	CAN-0030 Attestations		5/20/11	6/10/11	
28.	N/A	CAN-0039--Draft CAN-0039 DOE Form 407	CAN-0039 DOE Form 407		5/20/11	6/10/11	

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29.	Project 2010-05.1	Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)			6/10/11	7/11/11	
30.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-025-2, MOD-027-1, PRC-019-1	MOD-025-2 MOD-027-1 PRC-019-1		6/15/11	7/15/11	Yes 7/15/11
31.	Project 2010-07	Project 2010-07 – Generator Requirements at the Transmission Interface – Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards		6/17/11	7/17/11	Yes 7/15/11
32.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-026-1 and PRC-024-1	MOD-026-1 and PRC-024-1		6/15/11	8/1/11	Yes 8/1/11
33.	NERC RoP	Proposed Changes to NERC Rules of Procedure and associated Appendices (Appendix 4B – Sanction Guidelines; and Appendix 4C – Compliance Monitoring and Enforcement Program)	Appendices 4B and 4C		6/30/11	8/15/11	
34.	N/A	Compliance Application Notice (CAN) Process	CAN Process		8/15/11	9/6/11	Yes 9/6/11
35..	N/A	CAN-0016 CIP-001 R1 - Sabotage Reporting Procedure	CAN-0016 CIP-001, R1		8/15/11	9/6/11	Yes 9/6/11
36.	N/A	DRAFT CANs Posted for Comment and Retirement of CAN-0001 through 0004	CAN-0001 through 0004 Retirement		8/31/11	9/21/11	
37.	NERC RSDP	NERC 2012-2014 Reliability Standards Development Plan	2012-2014 RSDP		9/12/11	9/26/11	Yes 9/26/11
38.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		8/15/11	9/28/11	Yes 9/28/11
39.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Definition of BES	BES Definition		8/26/11	10/10/11	Yes 10/10/11

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40.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Technical Principles for Demonstrating BES Exceptions	Technical Principles for Demonstrating BES Exceptions		8/26/11	10/10/11	Yes 10/10/11
41.	N/A	New CAN Template, five DRAFT CANs for Industry review and CANs Status posted to NERC Compliance's Web site.	CANs		9/23/11	10/14/11	Yes 10/14/11
42.	RoP	Proposed Changes to NERC Rules of Procedure and All Appendices			9/2/11	10/17/11	
43.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Rules of procedure Modifications to Support BES Exception Requests	RoP Section 509, Section 1703 and Appendix 5C		9/13/11	10/27/11	Yes 10/27/11
44.	N/A	CAN-0010--Definition of "Annual" and Implementation of Annual Requirements	CAN-0010 Definition of Annual		10/10/11	10/31/11	Yes 10/31/11
45.	N/A	CAN-0011--PRC-005-1 R2: New Equipment	CAN-0011 PRC-005-1 R2		10/10/11	10/31/11	Yes 10/31/11
46.	N/A	CAN-0012--Completion of Periodic Activity Requirements During Implementation Plan	CAN-0012 Completion of Periodic Activity Requirements		10/10/11	10/31/11	Yes 10/31/11
47	N/A	CAN-0013--PRC-023 R1 and R2 Effective Dates for Switch-on-to-Fault Schemes	CAN-0013 PRC-023 R1 and R2		10/10/11	10/31/11	
48.	N/A	CAN-0015--Unavailability of NERC Software Tools	CAN-0015 NERC Tools		10/10/11	10/31/11	Yes 10/31/11
49.	N/A	CAN-0022--VAR-002-1.1b R1 and R3 Generator Operation in Manual Mode	CAN-0022 VAR-002-1.1b R1 and R3		10/10/11	10/31/11	
50.	N/A	CAN-0024--CIP-002 R3 Routable Protocols and Data Diode Devices	CAN-0024 CIP-002, R3		10/10/11	10/31/11	Yes 10/31/11
51.	N/A	CAN-0026--TOP-006 R3 Protection Relays	CAN-0026 TOP-006, R3		10/10/11	10/31/11	Yes 10/31/11
52.	N/A	CAN-0028--TOP-006-1 R1.2 Reporting Responsibilities	CAN-0028 TOP-006-1, R1.2		10/10/11	10/31/11	

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53.	N/A	CAN-0020--TPL-002, TPL-003, TPL-004 and TOP-002 Equipment Maintenance Outages	CAN-0020 TPL-002, TPL-003, TPL-004 and TOP-002		10/19/11	11/9/11	
54.	N/A	CAN-0030--Attestations	CAN-0030		10/19/11	11/9/11	
55.	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	MOD-028, R3.1		10/3/11	11/16/11	Yes 11/16/11
56.	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Interpretation of COM-002-2, R2		10/4/11	11/18/11	Yes 11/18/11
57.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		10/5/11	11/18/11	Yes 11/18/11
58.	N/A	Draft Directive Regarding Generator Transmission Leads	Draft Directive #2011 CAG-001		10/17/11	11/18/11	Yes 11/18/11
59.	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-1 R1.1 by Progress Energy	Interpretation of CIP-006-1, R1.1		10/12/11	11/21/11	Yes 11/21/11
60.	N/A	CAN-0040 - BAL-003 Frequency Bias Calculation			11/2/11	11/23/11	
61.	N/A	CAN-0043 - PRC-005 Protection System Maintenance and Testing Evidence	PRC-005 Evidence		11/2/11	11/23/11	Yes 11/22/11
62.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1			12/8/11	Yes 12/8/11
63.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2			12/12/11	Yes 12/12/11
64.	N/A	Draft CAN-0027: TOP-003 R2 Coordination of Scheduled Outages	CAN-0027 TOP-003, R2		11/22/11	12/14/11	
65.	NERC RoP	Proposed Changes to the NERC Rules of Procedure and Associated Appendices			11/7/11	12/22/11	

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66.	NERC RoP	Notice of Revisions to Proposed New Sections 1.1.24 and 5.11 of Appendix 4C of the NERC Rules of Procedure, as Originally Posted for Comment on November 7, 2011			11/22/11	12/22/11	
67.	Regional Standard	Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		11/22/11	12/22/11	
68.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1 (Version 5 CIP Standards)	Version 5 CIP Standards		11/7/11	1/6/12	Yes 1/6/12
69.	Project 2007-03	Project 2007-03 - Real-time Transmission Operations - TOP-001-2, TOP-002-3 and TOP-003-2	TOP-001-2 TOP-002-3 TOP-003-2		12/14/11	1/12/12	Yes 1/12/12
70.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition, Phase 2		1/4/12	2/3/12	Yes 2/3/12
71.	N/A	Order 754 - Request for Data or Information	Data Request		12/22/11	2/6/12	Yes 2/6/12
72.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001 COM-002 IRO-001-3		1/9/12	2/9/12	Yes 2/8/12
73.	WECC Regional Standard	Regional Reliability Standard BAL-004-WECC-02 - Automatic Time Error Correction	BAL-004-WECC-02		1/23/12	3/9/12	
74.	WECC Regional Standard	Regional Reliability Standard BAL-001-0.1a - Real Power Balancing Control Performance - WECC Variance	BAL-001-0.1a		1/23/12	3/9/12	
75.	N/A	NERC Functional Model Demand Response Functions and Entities	NERC Functional Model		2/13/12	3/14/12	
76.	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 for WECC	Interpretation of CIP-004-1		2/8/12	3/23/12	Yes 3/23/12

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77.	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Interpretation of CIP-002-1, R3		2/8/12	3/23/12	Yes 3/23/12
78.	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Interpretation of VAR -002		2/8/12	3/23/12	Yes 3/23/12
79.	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing - PRC-005	PRC-005-2		2/28/12	3/28/12	Yes 3/28/12
80.	Project 2007-09	Project 2007-09 Generator Verification - MOD-026-1 and PRC-024-1	MOD-026-1 and PRC-024-1		2/29/12	3/29/12	Yes 3/29/12
81.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface - FAC-003-X, FAC-003-3	FAC-003-X FAC-003-3		3/9/12	4/9/12	Yes 4/9/12
82.	Project 2007-09	Project 2007-09 Generator Verification - MOD-025-2, MOD-027-1, and PRC-019-1	MOD-025-2 MOD-027-1 PRC-019-1		2/29/12	4/16/12	Yes 4/16/12
83.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface - PRC-005-1.1a	PRC-005-1.1a		3/2/12	4/16/12	Yes 4/16/12
84.	Project 2007-03	Project 2007-03 - Real-time Transmission Operations	TOP-001 through TOP-008 and PER-001		3/22/12	4/20/12	Yes 4/20/12
85.	Project 2012-INT-02	Request for Interpretation - Project 2012-INT-02 TPL-003-0a and TPL-004-0 for SPCS	Interpretation of TPL-003-0a and TPL-004-0		4/24/12	5/4/12	
86.	Project 2008-06	Project 2008-06 - Cyber Security Order 706 Version 5 CIP	CIP-002 and CIP-003 - Comment Form A		4/12/12	5/21/12	Yes 5/20/12
			CIP-004 thru CIP-007 - Comment Form B		4/12/12	5/21/12	Yes 5/20/12
			CIP-008 thru CIP-011 - Comment Form C		4/12/12	5/21/12	Yes 5/20/12

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			Definitions and Implementation Plan - Comment Form D		4/12/12	5/21/12	Yes 5/20/12
87.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		4/25/12	5/24/12	Yes 5/24/12
88.	Project 2007-12	Project 2007-12 Frequency Response Technical Conferences			5/30/12	6/15/12	
89.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003		5/7/12	6/20/12	Yes 6/20/12
90.	N/A	Adequate Level of Reliability Revised Definition and Associated Documents	Adequate Level of Reliability (ALR)		4/25/12	6/25/12	Yes 6/25/12
91.	N/A	Order 754 - Request for Data or Information	Data Request		5/11/12	6/25/12	Yes 6/25/12
92.	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR - 002 for Constellation	Interpretation of VAR -002		5/22/12	6/27/12	Yes 6/27/12
93.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		5/29/12	6/27/12	Yes 6/27/12
94.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserve	BAL-001-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-002-2		6/4/12	7/3/12	Yes 7/3/12
			BAL-012-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-013-1		6/4/12	7/3/12	Yes 7/3/12
95.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		5/21/12	7/5/12	Yes 7/5/12
96.	N/A	Cost Effective Analysis Process (CEAP) for NERC ERO Standards	CEAP		5/7/12	7/6/12	Yes 7/6/12
97.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001, COM-002 and IRO-001-3		6/7/12	7/6/12	Yes 7/6/12
98.	Project 2006-02	Project 2006-02 – Assess Transmission Future Needs and Develop Transmission Plans	TPL-002-1b, footnote ‘b’ and TPL-001-3, footnote 12		6/19/12	7/9/12	Yes 7/9/12

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99.	N/A	Standard Processes Manual Revisions to Implement SPIG Recommendations	SPIG Reco		6/20/12	7/19/12	Yes 7/19/12
100.	Project 2012-INT-02	Project 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for System Protection and Control Subcommittee	- Interpretation of TPL-003-0a and TPL-004-0		6/20/12	7/20/12	Yes 7/19/12
101.	Project 2012-INT-05	Interpretation of 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		6/27/12	7/27/12	Yes 7/27/12
102.	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision to Address Interpretation of VAR-002 for Constellation	Rapid Revision to VAR-002		7/18/12	7/27/12	Yes 7/26/12
103.	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Rapid Revision of TOP-006		6/14/12	7/30/12	Yes 7/27/12
104.	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Glossary of Terms		6/19/12	8/2/12	Yes 8/2/12
105.	N/A	Reliability Guideline: System Operator Verbal Communications – Current Industry Practices	System Operator Verbal Communications		6/26/12	8/10/12	Yes 8/9/12
106.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		7/27/12	8/27/12	Yes 8/27/12
107.	Project 2010-11	Project 2010-11 - TPL Table 1 Order TPL-002-1b, footnote ‘b’ and TPL-001-3, footnote 12	TPL-002-1b, footnote ‘b’ and TPL-001-3, footnote 12		7/31/12	8/29/12	Yes 8/29/12
108.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs			7/31/12	8/30/12	
109.	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group			7/25/12	9/4/12	
110.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		8/3/12	9/4/12	Yes 9/4/12
111.	Project 2010-05.1	Project 2010-05.1 - Protection Systems: Phase 1 (Misoperations)			7/25/12	9/7/12	Yes 9/7/12

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112.	N/A	Definition of Adequate Level of Reliability	Adequate Level of Reliability (ALR)		8/15/12	9/13/12	Yes 9/13/12
113.	N/A	2013-2015 Reliability Standards Development Plan	2013-2015 RSDP		8/17/12	9/18/12	Yes 9/18/12
114.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols	COM-003-1		8/22/12	9/20/12	Yes 9/20/12
115.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		8/29/12	9/27/12	
116.	SPP Regional Standard	Regional Reliability Standard PRC-006-SPP-01 Automatic Underfrequency Load Shedding	PRC-006-SPP-01		8/15/12	9/28/12	
117.	Project 2008-06 Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		9/11/12	10/10/12	Yes 10/10/12
			RSAW		9/11/12	10/10/12	Yes 10/10/12
118.	MRO SPM	Regional Reliability Standards - MRO Standards Process Manual			8/28/12	10/11/12	
119.	N/A	Standard Process Manual Revisions to Implement SPIG Recommendations	SPIG Reco		8/29/12	10/12/12	Yes 10/10/12
120.		Revisions to Outstanding VRFs and VSLs			9/5/12	10/19/12	
121.	Project 2013-01	Project 2013-01 - Cold Weather Preparedness			9/25/12	10/24/12	
122.	Project 2007-09	Project 2007-09 - Generator Verification			9/28/12	10/29/12	
123.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System			10/4/12	11/5/12	
124.	2007-12	Project 2007-12 - Frequency Response			10/5/12	11/7/12	
125.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		10/26/12	11/7/12	
126.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025		10/5/12	11/7/12	

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127.	N/A	IRO-006-WECC-2			10/3/12	11/16/12	
128.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B			10/5/12	11/19/12	
129.	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Interpretation of TPL-003-0a and TPL-004-0		10/22/12	12/5/12	Yes 12/5/12
130.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		10/25/12	12/10/12	Yes 12/10/12
131.	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	- Interpretation of CIP-003-3		11/9/12	12/10/12	Yes 12/10/12
132.	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	- Interpretation of CIP-007-3		11/9/12	12/10/12	Yes 12/10/12
133.	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols - RSAW	COM-003-1		11/14/12	12/13/12	Yes 12/13/12
			COM-003-1 RSAW		11/14/12	12/13/12	Yes 12/13/12
134.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		11/16/12	12/17/12	Yes 12/17/12
135.	Project 2012-INT-05	Project 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		11/6/12	12/20/12	Yes 12/20/12
136.	N/A	Standard Processes Manual to Implement SPIG Revisions	SPIG Reco		11/21/12	12/20/12	Yes 12/20/12
137.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B	TPL-002-1b, footnote ‘b’ and TPL-001-3, footnote 12		12/10/12	1/11/13	Yes 1/11/13
138.	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	PRC-024-1		12/12/12	1/11/13	Yes 1/11/13
139.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-012-1	BAL-012-1		11/30/12	1/14/13	Yes 1/14/13
140.	N/A	Reliability Guideline--Draft Generating Unit Winter Weather Readiness - Current Industry Practices			12/20/12	2/4/13	Yes 2/4/13
141.	Project 2010-05-1	Project 2010-05-1 Protection System Misoperations					Yes 2/20/13
142.	Project 2007-09	Project 2007-09 Generator Verification - PRC-024-1	PRC-024-1	Formal	1/25/13	2/25/13	Yes 2/25/13

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143.	N/A	Rapid Revision Procedure		Informal	2/25/13	3/6/13	Yes 3/6/13
144.	Project 2010-13-2	Project 2010-13-2 - Phase 2 of Relay Loadability - Generation - PRC-025-1	PRC-025-1	Formal	1/25/13	3/11/13	Yes 3/11/13
			Supplemental SAR	Informal	1/25/13	3/11/13	Yes 3/11/13
			Cost Effectiveness	CEAP Pilot	1/25/13	3/11/13	Yes 3/11/13
			RSAW	Feedback	1/25/13	3/11/13	Yes 3/11/13
145.	Project 2012-INT-04	Interpretation 2012-INT-04 - Interpretation of CIP-007 for ITC	Interpretation of CIP-007	Formal	2/6/13	3/22/13	Yes 3/22/13
146.	Project 2012-INT-06	Interpretation 2012-INT-06 - Interpretation of CIP-003 for Consumers Energy	Interpretation of CIP-003	Formal	2/6/13	3/22/13	Yes 3/22/13
147.	Project 2012-08-1	Project 2012-08-1 - Phase 1 of Glossary Updates--Statutory Definitions	Glossary of Terms	Formal	2/21/13	3/22/13	Yes 3/22/13
148.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003-1	COM-003-1	Formal	3/7/13	4/5/13	Yes 4/5/13
			RSAW	Feedback	3/7/13	4/5/13	Yes 4/5/13
149.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-001-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-002-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-013-1	Formal	3/12/13	4/25/13	Yes 4/25/13
150.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)	Draft SAR	Informal	4/5/13	5/6/13	Yes 5/6/13
			PRC-005-3	Formal	4/5/13	5/6/13	Yes 5/613
151.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation	PRC-023-3 PRC-025-1	Formal	4/25/13	5/24/13	Yes 5/24/13
152.	Project 2007-11	Project 2007-11 - Disturbance Monitoring — PRC-002 and PRC-018	SAR	Informal	5/03/13	6/03/13	Yes 6/3/13
153.	Project 2007-11	Project 2007-11 - Disturbance Monitoring PRC-002 and PRC-018	Request for Information	Informal	6/05/13	7/05/13	
154.	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	PRC-001 and PRC-027		6/04/13	7/03/13	Yes 7/03/13

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
155.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition		5/29/13	7/12/13	Yes 7/12/13
156.	TRE Regional Standard	Regional Reliability Standard - BAL-001-TRE-01	BAL-001-TRE-01		5/31/13	7/15/13	
157.	N/A	NPCC Regional Standards Process Manual	NPCC RSPM		6/06/13	7/22/13	
158.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003-1		6/20/13	7/19/13	Yes 7/19/13
159.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025-1		6/20/13	7/19/13	Yes 7/19/13
160.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023	PRC-023-3	Formal	6/20/13	8/05/13	Yes 8/5/13
161.	N/A	SPP RE Regional Standards Process Manual	SPP RSPM		6/26/13	8/09/13	
162.	Project 2013-03	Project 2013-03 - Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	6/27/13	8/12/13	Yes 8/12/13
163.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005	PRC-005-3	Formal	7/10/13	8/23/13	Yes 8/23/13
164.	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards	INT-004-3 INT-006-4 INT-009-2 INT-010-2 INT-011-1	Informal	7/25/13	8/23/13	Yes 8/23/13
165.	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	MOD-001-2	Formal	7/11/13	8/26/13	Yes 8/26/13
166.	Project 2010-01	Project 2010-01 - Training - PER-005-2	PER-005-2	Formal	7/19/13	9/03/13	Yes 9/3/13
167.	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-001-4 VAR-002-3	Formal	7/19/13	9/03/13	Yes 9/3/13
168	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	MOD-032-1 MOD-033-1	Formal	7/22/13	9/04/13	Yes 9/4/13

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169.	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	7/22/13	9/04/13	Yes 9/4/13
170	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System – Phase 2	BES Definition Phase 2	Formal	8/6/13	9/4/13	Yes 9/4/13
171	Project 2012-13	Project 2012-13 - NUC Five-Year Review	NUC-001-2	5-year review	7/26/13	9/9/13	Yes 9/9/13
172	2014-2016 RSDP	2014-2016 Reliability Standards Development Plan	Reliability Standards Development Plan	Annual Review	8/30/13	9/13/13	Yes 9/13/13
173	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-001-1 FAC-002-1	5-year review	8/1/13	9/16/13	Yes 9/16/13
174	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-003-3 FAC-008-3 FAC-010-2.1 FAC-011-2 FAC-013-2 FAC-014-2	5-year review	8/1/13	9/16/13	Yes 9/16/13
175	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	BAL-002-2	Formal	8/2/13	9/16/13	Yes 9/16/13
176	Project 2009-03	Project 2009-03 — Five-Year Review of Emergency Operations EOP-001, EOP-002, EOP-003, and IRO-001	EOP-001-2.1b EOP-002-3.1 EOP-003-2	5-year review	8/6/13	9/19/13	Yes 9/19/13
177	Project 2012-09	Project 2012-09 IRO Five-Year Review	IRO-003-2 IRO-004-2 IRO-005-4 IRO-006-5 IRO-006-East IRO-008-1 IRO-009-1 IRO-010-1a	5-year review	8/7/13	9/20/13	Yes 9/20/13
178	Project 2008-02	Project 2008-02 Undervoltage Load Shedding	Revised SAR	Informal	9/10/13	10/9/13	Yes 10/9/13
179	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	9/4/13	10/18/13	Yes 10/18/13
180	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition	Formal	9/27/13	10/28/13	Yes 10/28/13

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181	Project 2007-02	Project 2007-02 Operating Personnel Communications Protocols	COM-002-4	Formal	10/21/13	11/7/13	Yes 11/4/13
182	Project 2010-01	Project 2010-01 Training	PER-005-2	Formal	9/27/13	11/12/13	Yes 11/12/13
183	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	Various INT Standards	Formal	9/30/13	11/13/13	Yes 11/13/13
184	Project 2012-05	Project 2012-05 ATC Revisions (MOD A)	MOD-001-2	Formal	10/4/13	11/20/13	Yes 11/18/13
185	Project 2010-03	Project 2010-03 Modeling Data (MOD B)	MOD-032-1, MOD-033-1	Formal	10/07/13	11/20/13	
186	Project 2010-04	Project 2010-04 Demand Data (MOD C)	MOD-031-1	Formal	10/09/13	11/22/13	Yes 11/22/13
187	Project 2013-04	Project 2013-04 Voltage and Reactive Control	VAR-001-4, VAR-002-3	Formal	10/11/13	11/25/13	Yes 11/25/13
188	Project 2009-03	Project 2009-03 Emergency Operations	SAR	Informal	11/06/13	12/05/13	Yes 12/5/13
189	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-002-2	Formal	10/28/13	12/11/13	Yes 12/11/13
190	Project 2007-11	Project 2007-11 - Disturbance Monitoring	PRC-002-2	Formal	11/01/13	12/16/13	Yes 12/16/13
191	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-027	Formal	11/04/13	12/18/13	Yes 12/18/13
192	Project 2014-01	Project 2014-01 - Standards Applicability for Dispersed Generation Resources	SAR	Formal	11/20/13	12/19/13	Yes 12/19/13
193	Project 2010-01	Project 2010-01 Training - PER-005-2	PER-005-2	Formal	12/4/13	1/22/14	Yes 1/17/14
194	Project 2010-03	Project 2010-03 Modeling Date - MOD B	MOD-033-1	Formal	12/6/13	1/22/14	Yes 1/21/14
195	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	INT-004-3 INT-010-2	Formal	1/10/14	1/24/14	Yes 1/22/14
196	Project 2007-02	Project 2007-02 Operating Personnel	COM-002-4	Formal	1/22/14	1/31/14	Yes 1/31/14
197	Project 2014-02	Project 2014-02 Standard Authorization Request – Cyber Security Standards	CIP SAR	Informal	1/17/14	2/18/14	Yes 2/18/14
198	2014 Work Plan	2014 Work Plan for NERC Reliability Standards Development	2014 Work plan			2/21/13	Yes 2/21/14

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199	Project 2010-17	Project 2010-17 Definition of Bulk Electric System - Phase 2	BES	Informal	1/29/14	2/27/14	Yes 2/27/14
200	Project 2010-05.1	Project 2010-05.1 Protection System: Phase 1 (Misoperations) - PRC-004-3	PRC-004-3	Formal	1/17/14	3/11/14	Yes 3/2/14
201	Project 2012-13	Project 2012-13 NUC-Nuclear Plant Interface Coordination Standard Authorization Request	NUC-001-2.1 SAR	Informal	2/12/14	3/13/14	Yes 3/13/14
202	Project 2010-05.2	Project 2010-05.2 Special Protection Systems (Phase 2 of Protection Systems) - SAR	SAR	Informal	2/18/14	3/19/14	Yes 3/19/14
203	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	SAR	Formal	02/21/14	03/24/14	Yes 3/24/14
204	Project 2014-03	Technical Conferences on Revisions to TOP/IRO Reliability Standards	Technical Conference Topics	Informal	03/11/14	03/24/14	
205	Project 2014-04	Project 2014-04 - Physical Security	SAR	Informal	03/21/14	03/28/14	Yes 3/28/14
206	Project 2010-14.2	Project 2010-14.2 - Periodic Review of BAL Standards	Reco to Revise BAL-005 and BAL-006	Formal	02/21/14	04/07/14	
207	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Informal	03/11/14	04/09/14	Yes 4/9/14
208	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	02/25/14	04/10/14	Yes 4/10/14
209	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-002-3	Formal	02/27/14	04/14/14	Yes 4/14/14
210	Project 2008-02	Project 2008-02 - Undervoltage Load Shedding - PRC-010, PRC-020, PRC-021 and PRC-022	PRC-010-1	Informal	03/17/14	04/16/14	Yes 4/16/14
211	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	CIP-014-1	Formal	04/10/14	04/24/14	Yes 4/24/14
212	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Informal	03/28/14	04/28/14	Yes 4/28/14

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213	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	04/17/14	05/05/14	Yes 5/5/14
214	Project 2010-02	Project 2010-02 – Connecting New Facilities to the Grid	FAC-001-1 FAC-002-1	Formal	04/01/14	05/15/14	Yes 5/15/14
215	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Informal	04/22/14	05/21/14	Yes 5/21/14
216	Project 2012-13	Project 2012-13 Nuclear Plant Interface Coordination	NUC-001-3	Formal	04/08/14	05/22/14	Yes 5/22/14
217	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays)	PRC-005-X	Formal	04/17/14	06/03/14	Yes 6/3/14
218	Project 2010-13.3	Project 2010-13.3 Relay Loadability: Stable Power Swings	PRC-026-1	Formal	04/25/14	06/09/14	Yes 6/9/14
219	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	05/09/14	06/25/14	Yes 6/25/14
221	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Informal	05/23/14	06/23/14	Yes 6/23/14
222	Project 2010-05-1	Project 2010-05-1 Protection System – Phase 1 – Misoperations	PRC-004	Formal	05/16/14	07/09/14	Yes 7/9/14
223	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	05/19/14	07/02/14	Yes 7/2/14
224	Project 2014-02	Project 2014-02 CIP Version 5 Revisions – Cyber Security Standards	CIP-002 to CIP-011	Formal	06/02/14	07/17/14	Yes 7/16/14
225	Project 2015-2017	Project 2015-2017 Reliability Standard		Informal		7/21/14	Yes 7/21/14

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		Development Plan					
226	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Formal	7/16/14	7/25/14	Yes 7/25/14
227	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	06/12/14	7/29/14	Yes 7/29/14
228	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	06/13/14	07/30/14	Yes 7/30/14
229	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Formal	06/23/14	08/8/14	Yes 8/6/14
230	Project 2010-14-2	Project 2010-14-2 Balancing Authority Reliability-based Control Standard Authorization Request for BAL-005 and BAL-006	BAL-005 BAL-006	Informal	07/16/14	08/14/14	Yes 8/12/14
231	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Formal	07/2/14	08/15/14	Yes 8/13/14
232	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-004-2.1a(X) PRC-004-3(X)	Formal	07/10/14	08/26/14	Yes 8/25/14
233	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays) – PRC-005-X	PRC-005-X	Formal	07/30/14	09/12/14	Yes 9/12/14
234	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	08/6/14	09/19/14	Yes 9/22/14
235	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	08/19/14	10/03/14	Yes 10/2/14

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236	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	09/26/14	10/06/14	Yes 10/6/14
237	Project 2008-02	Project 2008-02: Underfrequency Load Shedding (UFLS)	PRC-006-2	Formal	08/21/14	10/08/14	Yes 10/7/14
238	Project 2013-03	Project 2013-03: Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	08/27/14	10/10/14	Yes 10/10/14
239	NERC Rules of Procedure	NERC Rules of Procedure	NERC Rules of Procedure	Formal	08/26/14	10/10/14	Yes 10/14/14
240	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems Phase 2 of Protection Systems	RAS Definition	Formal	08/29/14	10/14/14	Yes 10/14/14
241	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	VAR-002-2b(X) VAR-002-4	Formal	08/27/14	10/16/14	Yes 10/16/14
242	Project 2014-02	Project 2014-02 CIP Version 5 Revisions – Cyber Security Standards	CIP-003-6 CIP-010-2 CIP-003-X CIP-004-X CIP-007-X CIP-010-X CIP-011-X	Formal	09/03/14	10/17/14	Yes 10/17/14
243	Project 2009-03	Project 2009-03 Emergency Operations	EOP-011-1	Formal	09/05/14	10/20/14	Yes 10/20/14
244	Project 2007-06	Project 2007-06 System Protection Coordination PRC-027-1 (Preliminary Draft 5)	PRC-027-1	Informal	10/01/14	10/21/14	Yes 10/21/14
245	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	09/05/14	10/21/14	Yes 10/21/14
246	Project 2014-01	Project 2014-01 Applicability for Dispersed Generation	PRC-004-2.1a(X) PRC-004-4	Formal	09/05/14	10/22/14	Yes 10/22/14
247	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	10/10/14	11/10/14	Yes 11/10/14
248	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1	TPL-007-1	Formal	10/28/14	11/21/14	Yes 11/24/14
249	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	11/04/14	11/24/14	Yes 11/25/14
250	Project 2014-01	Project 2014-01 – Standards Applicability	PRC-001-1.1 PRC-019-2	Formal	11/05/14	12/23/14	Yes 12/22/14

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		for Dispersed Generation Resources	PRC-024-1				
251	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	12/29/14	1/7/15	Yes 1/6/15
252	Project 2014-02	Project 2014-02 CIP Version 5 Revisions	CIP-003-7 CIP-004-7 CIP-007-7 CIP-010-3 CIP-011-3 CIP-003-7 CIP-010-3 Implementation Plan	Formal	12/30/14	1/9/15	Yes 1/9/15
253	Project 2014-04	Project 2014-04 Physical Security SAR	SAR	Informal	12/15/14	1/13/15	Yes 1/12/15
254	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	White Paper Appendix A Appendix B	Informal	12/22/14	1/20/15	Yes 1/20/15
255	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-5	Informal	12/22/14	1/20/15	Yes 1/22/15
257	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	1/29/15	3/18/15	Yes 3/16/15
258	Reliability Guideline	Reliability Guideline: Loss of Real-Time Reliability Tools Capability/Loss of Equipment Significantly Affecting ICCP Data		Formal	2/19/15	4/6/15	Yes 4/6/15
259	Project 2008-02.2	Project 2008-02.2 Phase 2 UVLS: Misoperation	PRC-010-2	Formal	2/20/15	4/7/15	Yes 4/7/15
260	Project 2014-04	Project 2014-04 Physical Security	CIP-014-2	Formal	2/20/15	4/9/15	Yes 4/9/15
261	Project 2015-04	Project 2015-04 Alignment of Terms	SAR	Formal	2/24/15	4/13/15	Yes 4/13/15
262	Project 2007-17.4	Project 2007-17.4 PRC-005 Order No. 803 Directives	SAR	Informal	3/12/15	4/10/15	Yes 4/13/15
263	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	SAR	Informal	3/16/15	4//15/15	Yes 4/15/15
264	Project 2010-14.2.2	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls: Time Error Correction	SAR	Informal	3/17/15	4//15/15	Yes 4/15/15

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265	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-008-1	Informal	3/27/15	5/11/15	Yes 5/11/15
266	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-006-2	Informal	3/27/15	5/11/15	Yes 5/11/15
267	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-005-2	Informal	3/27/15	5/11/15	Yes 5/11/15
268	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-004-2	Informal	3/27/15	5/11/15	Yes 5/11/15
269	Project 2007-06	Project 2007-06 System Protection Coordination PRC-027-1 (Draft 5)	PRC-027-1	Formal	4/1/15	5/15/15	Yes 5/15/15
270	Project 2010-04.1	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	SAR	Informal	4/16/15	5/19/15	Yes 5/19/15
271	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems – RAS	PRC-012-2	Informal	4/30/15	5/20/15	Yes 5/20/15
272	Project 2015-03	Project 2015-03 Periodic Review of System Operating Limit Standards	FAC-010-3 FAC-011-3 FAC-014-2	Formal	5/4/15	6/17/15	Yes 6/17/15
273	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	IRO-006-East-2 IRO-009-2	Formal	5/21/15	7/8/15	Yes 7/8/15
274	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	PRC-005-3	Formal	6/11/15	7/10/15	Yes 7/10/15
275	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generations Resources	PRC-004-2.1 PRC-005-2 PRC-005-3	Informal	6/12/15	7/13/15	Yes 7/13/15
276	Project 2015-07	Project 2015-07 Internal Communications Capabilities	COM-001-2	Informal	6/11/15	7/15/15	Yes 7/15/15
277	Project 2015-04	Alignment of Terms	Glossary Terms	Formal	6/12/15	7/23/15	Yes 7/23/15
278	Project 2009-02	Real-time Monitoring and Analysis Capabilities	SAR	Formal	7/16/15	8/17/15	Yes 8/17/15
279	NERC 2016-2018	Reliability Standards Development Plan	Development Plan	Formal	7/16/15	8/17/15	Yes 8/17/15
280	Project 2015-08	Emergency Operations	EOP-004-2 EOP-005-2 EOP-006-2 EOP-008-1	Informal	7/21/15	8/19/15	Yes 8/19/15
281	Project 2010-14.1	Phase 1 of Balancing Authority Reliability-	BAL-002-2	Formal	7/7/15	8/20/15	Yes 8/20/15

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		based Controls					
282	Project 2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls: Time Error Correction	BAL-004-0	Survey	8/12/15	8/25/15	Yes 8/25/15
283	Project 2007-06.2	Phase 2 of System Protection Coordination	TOP-009-1	Formal	7/29/15	9/11/15	Yes 9/11/15
284	Project 2007-06	System Protection Coordination	PRC-027-1	Formal	7/29/15	9/11/15	Yes 9/11/15
285	Project 2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls	BAL-005-1 BAL-006-3	Formal	7/30/15	9/14/15	Yes 9/14/15
286	Project 2007-17.4	PRC-005 FERC Order No. 803 Directive	PRC-005-6	Formal	7/30/15	9/16/15	Yes 9/16/15
287	Project 2010-04.1	MOD-031 FERC Order No. 804 Directives	MOD-031-2	Formal	7/31/15	9/18/15	Yes 9/18/15
288	Project 2015-09	Establish and Communicate System Operating Limits	FAC-010-3 FAC-011-3 FAC-014-2	Informal	8/20/15	9/21/15	Yes 9/21/15
289	Project 2010-07.1	Vegetation Management	FAC-003-3	Informal	8/24/15	9/28/15	Yes 9/28/15
290	Project 2010-05.3	Phase 3 of Protection Systems: Remedial Action Schemes	PRC-012-2	Formal	8/20/15	10/5/15	Yes 10/5/15
291	Project 2009-02	Real-time Reliability Monitoring and Analysis Capabilities	IRO-018-1 TOP-010-1	Formal	9/24/15	11/9/15	Yes 11/9/15
292	Project 2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls	BAL-004-0	Formal	9/24/15	11/12/15	Yes 11/12/15
293	Project 2015-07	Internal Communications Capabilities	COM-001-3	Formal	9/25/15	11/16/15	Yes 11/16/15
294	Project 2007-06.2	Phase 2 of System Protection Coordination	TOP-009-1	Formal	10/6/15	11/19/15	Yes 11/19/15
295	Project 2010-07.1	Vegetation Management	FAC-003-3	Formal	10/30/15	12/16/15	Yes 12/16/15
296	Project 2015-10	Single Points of Failure SAR	TPL-001	Informal	11/12/15	12/17/15	Yes 12/17/15
297	Project 2010-05.3	Phase 3 of Protection Systems RAS	PRC-012-2	Formal	11/25/15	1/8/16	Yes 1/8/16
298	Project 2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls	BAL-005-1 FAC-001-3 BAL-006-2	Formal	12/31/15	1/11/16	Yes 1/11/16
299	Project 2009-02	Real-time Reliability Monitoring and Analysis Capabilities	IRO-018-1 TOP-010-1	Formal	12/10/15	1/25/16	Yes 1/25/16
300	Project 2016-01	Modifications to TOP and IRO Standards	SAR	Informal	1/22/16	2/22/16	Yes 2/22/16
301	Project 2010-05.3	Phase 3 of Protection Systems RAS	PRC-012-2	Formal	2/3/16	3/18/16	Yes 3/18/16
302	Project	Modifications to CIP	SAR	Informal	3/23/16	4/21/16	Yes

RSC Meeting #16-6, Agenda Item 6.3: Comment History

(As of 11/21/2016)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	2016-02	Standards					4/21/16
303	Project 2007-06.2	Phase 2 of System Protection Coordination	PER-006-1 & Two Definitions	Formal	3/10/16	4/25/16	Yes 4/25/16
304	Project 2015-07	Internal Communications Capabilities	COM-001-3	Formal	3/23/16	5/9/16	Yes 5/6/16
305	CEP	Cost Effectiveness Pilot	TPL-001-4	Informal	4/27/16	5/26/16	Yes 5/26/16
306	Project 2013-03	Geomagnetic Disturbance Mitigation Revised White Papers	SAR	Informal	5/12/16	6/13/16	Yes 6/13/16
307	Project 2015-10	Single Points of Failure	SAR	Informal	5/26/16	6/24/16	Yes 6/24/16
308	Project 2016-02	Modifications to CIP Standards	SAR	Informal	6/1/16	6/30/16	Yes 6/30/16
309	Draft 2017-2019	Reliability Standards Development Plan	RSDP	Informal	6/20/16	7/19/16	Yes 7/19/16
310	EPR	Enhanced Periodic Review Standing Review Team	Standards Grading	Informal	6/30/16	8/1/16	Yes 8/1/16
311	Project 2016-01	Modifications to TOP and IRO Standards	IRO-002-5 TOP-001-4	Formal	6/20/16	8/3/16	Yes 8/3/16
312	Project 2015-09	Establish and Communicate System Operating Limits	FAC-014-3	Formal	7/14/16	8/12/16	Yes 8/12/16
313	Project 2015-09	Establish and Communicate System Operating Limits	FAC-011-4	Formal	7/14/16	8/12/16	Yes 8/12/16
314	Project 2015-08	Emergency Operations	EOP-005-3 EOP-006-3 EOP-008-2	Formal	6/30/16	8/15/16	Yes 8/15/16
315	Project 2016-02	Modifications to CIP Standards	CIP-003-7	Formal	7/21/16	9/6/16	Yes 9/6/16
316	FMAG	Functional Model Advisory Group	Reliability Functional Model and Technical Document	Informal	7/21/16	9/7/16	Yes 9/7/16
317	Project 2015-08	Emergency Operations	EOP-004-4	Formal	7/25/16	9/8/16	Yes 9/8/16
318	Project 2015-INT-01	Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	CIP-002-5.1	Formal	7/27/16	9/12/16	Yes 9/12/16
319	Project 2016-01	Modifications to TOP and IRO Standards SAR	TOP-001-3 IRO-002-4	Formal	8/31/16	10/17/16	Yes 10/14/16
320	Project 2016-04	Modifications to PRC-025-1 SAR	PRC-025-1	Formal	9/16/16	10/18/16	Yes 10/18/16
321	Project 2016-03	Cyber Security Supply Chain Management	SAR	Informal	10/20/16	11/18/16	Yes 11/18/16
322	Project	Modifications of CIP	CIP-003-TCA	Informal	11/1/16	11/18/16	Yes

RSC Meeting #16-6, Agenda Item 6.3: Comment History

(As of 11/21/2016)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	2016-02	Standards					11/18/16

Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD16-8-000

August 16, 2016

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Lauren A. Perotti
Counsel for North American Electric Reliability Corporation

Reference: Joint Petition of the North American Electric Reliability Corporation and Northeast Power Coordinating Council for Approval of Retirement of Regional Reliability Standard PRC-002-NPCC-01

Dear Ms. Perotti:

On June 9, 2016, the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordination Council, Inc. (NPCC) filed a joint petition for Commission approval, pursuant to section 215(d)(1) of the Federal Power Act (FPA)[1] and Section 39.5[2] of the Commission's regulations, of the retirement of NPCC Regional Reliability Standard PRC-002-NPCC-01 (Disturbance Monitoring) and the two related NPCC regional definitions, Current Zero Time and Generating Plant.[3]

In the joint petition, NERC and NPCC state that the primary purpose of Regional Reliability Standard PRC-002-NPCC-01 is to ensure that adequate disturbance data is available to facilitate bulk electric system event analyses. NERC and NPCC explain that the issues addressed in the Regional Reliability Standard are now addressed by continent-wide Reliability Standard PRC-002-2 (Disturbance Monitoring and Reporting

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1 16 U.S.C. § 824o (2012).

2 18 C.F.R. § 39.5 (2015).

3 In 2011, the Commission approved Regional Reliability Standard PRC-002-NPCC-01 and the two related NPCC regional definitions. *See North. American. Electric. Reliability Corp.*, 137 FERC ¶ 61,043 (2011).

Requirements), approved by the Commission in 2015.[4] Reliability Standard PRC-002-2 imposes mandatory requirements concerning the monitoring and reporting of disturbances and provides greater continent-wide consistency regarding collection methods for data used in the analysis of disturbances on the Bulk-Power System. According to NERC and NPCC, Regional Reliability Standard PRC-002-NPCC-01 and the related definitions are now redundant and unnecessary for reliability and should be retired.

The NERC and NPCC joint petition was noticed on June 9, 2016, with interventions, comments and protests due on or before July 11, 2016. Dominion Resources Service, Inc. filed a timely motion to Intervene. No comments or protests were received.

The NERC and NPCC uncontested joint petition is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2015), effective as of the date of this order.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713 (2015).

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

[4] Order No. 814, *Disturbance Monitoring and Reporting Requirements Reliability Standard*, 152 FERC ¶ 61,198 (2015).

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

PRC-006-NPCC-02 Automatic Underfrequency Load Shedding

AGENDA FOR MEETING #2
October 20, 2016 9:00 a.m. – 4:00 p.m. EST
NPCC Office
1040 Avenue of Americas 10th Floor
New York, NY
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada) **Guest Code: 648814580**
Password: uP2aDM?6 (87223606 from phones)

Attendees:

	Name	Organization	Comment
1.	Guy Zito	Northeast Power Coordinating Council	In Person
2.	Ruida Shu	Northeast Power Coordinating Council	In Person
3.	Daniel Kidney	Northeast Power Coordinating Council	In Person
4.	Juan Villar	FERC	In Person
5.	Vincent Morissette	Hydro Québec TransÉnergie	In Person
6.	Dean Latulipe	National Grid	In Person
7.	Dan Taft	Con Edison	In Person
8.	Tim Kucey	PSEG Fossil	In Person
9.	Brian Robinson	Utility Services	In Person
10.	Ben Wu	Orange and Rockland	In Person
11.	Jeannette Gauthier	Hydro Québec TransÉnergie	Via Phone
12.	John McLaughlin	Eversource	Via Phone
13.	John Pearson	ISO-NE	Via Phone
14.	Nick Paratta	PLM	Via Phone
15.	Hamid Hamadani	Hydro One	Via Phone
16.	Lori Raub	UI	Via Phone
17.	Dennis Fuentes	FERC	Via Phone

Introductions and Chair's Remarks
Dan Taft called the meeting in order at 9:02AM.
Dan Taft the chair of the drafting team provided a brief introduction and background on the project.

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

Agenda Items:

Guy Zito and Juan Villar from FERC indicated the importance of having justifications on all decisions. (Retiring the standard etc.)

1. **Purpose of this Standard Drafting Team (SAR)**

2. **Review of Kick Off Meeting Minutes**

   Action Item:

   1. Find out from (TFSS) if there are any generators left in the NPCC foot print that trips over the curve. (Assigned to Brian Robinson on 10-20-16)
   2. Reach out to the continent wide standard drafting team members for PRC-006-2, find out how they handled the compensatory load shedding. (This action item is removed since it is not necessary)

3. **PRC-006-2, PRC-006-NPCC-1 and Directory 12**

4. **Review of Comparison Table**

   Requirement 1:
   After reviewing both requirements from the comparison table the drafting team did not agreed on a position for the requirement and will seek additional information. (Brian Robinson is tasked to get additional information from TFSS.)

   Requirement 2:
   Action Item:
   3. Consider possibly amending the requirement to capture additional data for the Planning Coordinator to run simulation and model. (Distributed Generation or smaller generation, Dean Latulipe will check with SS38.)
   4. Dan Taft will discuss with Rich Burke on the existing requirement language.

   Will remove the previous recommendation by Dan Taft which was to retire the requirement.

   Requirement 3:
   This requirement is linked to requirement 1. (Brian Robinson will seek additional information from TFSS on location and islanding.)

   Requirement 4:
   Considering adding a 30-day language in the requirement so it is consistent with R3.

   Requirement 5:
   Action Item:
   5. Dean Latulipe will draft some possible requirement language for requirement 5.
   6. Vincent Morissette is tasked to remove the Hydro Quebec curve from PRC-006-NPCC-02 Figure 1.

   Requirement 6:
   The drafting team agreed to retire requirement 6.

Requirement 7:
Action Item:

7. Dan Taft will verify with Rich Burke on where the 100MS and 200 MS came from and why. Also verify with Rich Burke on the 300MS total operating time if it includes the 100MS time delay on the UFLS Relay.

Requirement 8:
Dan Taft purposed to make a change to the frequency of the develop and review for inhibit thresholds.
Once every five years instead of once per calendar year to develop and review settings for inhibit thresholds.
Action Item:

8. Dan Taft will verify with Rich Burke on why it is necessary to review once per calendar year settings for inhibit thresholds.

Requirement 9:
See action item from requirement 8.

Requirement 10:
See action item from requirement 8.

Requirement 11:
See action item from requirement 8.

Requirement 12:
Consider revising language to specify planning coordinator to identify time period of interest.
Action Item:

9. Dan Taft will verify with Rich Burke on the purpose of this requirement and how it will impact the smaller utilities. Is a calculated value acceptable based on accountable meter data from upstream?

Requirement 13:
The drafting team decided to modify the language to “On or below the curve”.

Requirement 14:
The drafting team decided to keep the existing requirement without making any modification.

Requirement 15:
The drafting team decided to keep the existing requirement without making any modification.

Requirement 16:
Action Item:

10. Brian Robinson will verify this requirement with TFSS.

Requirement 17:
Action Item:

11. Brian Robinson will verify this requirement with TFSS.

Requirement 18:
Action Item:

12. Brian Robinson will verify this requirement with TFSS.

Requirement 19:
The drafting team decided to keep the existing requirement without making any modification.

Requirement 20:
The drafting team is considering a five-year frequency period, in line with the SS38 study.
20.1 Load shed at peak: Control area peak.
20.6 Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to Transmission Owners and Distribution Providers within its Planning Coordinator within 30 calendar days of a request.

Requirement 21:
Action Items:

13. Dan Taft will discuss the requirement with Rich Burke.

Requirement 22:
Action Items:

14. Dan Taft will discuss the requirement with Rich Burke.

Requirement 23:
Action Items:

15. Dan Taft will discuss the requirement with Rich Burke.

5. **Discussion on the process for approbation**

6. **Next Steps**
   Dan Taft adjourned the meeting at 3:45PM.

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.

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 Regional Standards Process Manager, NPCCstandard@npcc.org . The NPCC Regional Standards Process Manager 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:	PRC-006-NPCC-2
Request Date:	03-31-2015

RSAR Requester Information

Name: Brian Robinson		**RSAR Type (Check box for one of these selections.)**	
Company:	NPCC	☐	New Standard
Telephone: 802-241-1400		☒	Revision to Existing Standard
Fax:	(866) 214-8632	☐	Withdrawal of Existing Standard
Email:	Brian.Robinson@utilitysvcs.com	☐	Urgent Action

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

The purpose of the proposed RSAR is to review regional reliability standard PRC-006-NPCC-1 for potential revisions or retirements made necessary by NERC's PRC-006-1/PRC-006-2 Automatic Underfrequency Load Shedding and PRC-024-1/PRC-024-2 Generator Frequency and Voltage Protective Relay Settings standards.

PRC-006-NPCC-1 is to be reviewed to determine if the applicability of the standard needs to be revised in accordance with Project 2014-01 Dispersed Generation Resources.

PRC-006-NPCC-1 is to be reviewed in order 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.

Attachment C in PRC-006-NPCC-1 is to be reviewed 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.

PRC-006-NPCC-1 is to be reviewed in order to update 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.

Retiring PRC-006-NPCC-1 is to be considered if it is determined that it can be retired without sacrificing the ability to develop an effective underfrequency load shedding program.

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

To enhance efficiencies and cost effectiveness, it must be determined if PRC-006-NPCC-1 requirements can be revised or retired to address the new NERC BES definition, Paragraph 81, and eliminate redundancy leading to double jeopardy with PRC-006-1/PRC-006-2 and PRC-024-1/PRC-024-2 requirements without sacrificing the ability to develop an effective underfrequency load shedding program.

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

The requirements in PRC-006-NPCC-1 will be reviewed individually for revision or deletion with respect to the new NERC BES definition, and Paragraph 81. In addition, PRC-006-NPCC-1 will be reviewed against NERC's PRC-006-1/PRC-006-2 and PRC-024-1/PRC-024-2 2-2. PRC-006-1/PRC-006-2 mandates the establishment of design and documentation requirements for automatic underfrequency load shedding (UFLS) programs. PRC-024-1/PRC-024-2 mandate that Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions. These "umbrellas" encompasses the relevant requirements in PRC-006-NPCC-1. However, the relevant requirements in each of the standards are to be compared and the requirements of PRC-006-NPCC-1, if so determined, are revised or deleted to eliminate redundancy and the

concomitant double jeopardy. The review will also ensure that NERC Rules of Procedure, Section 312. Regional Reliability Standards, bullet 1that reads "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." will govern.

PRC-006-1/PRC-006-2 specifies in Requirement R4 that "Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years…" Revision to Attachment C of PRC-006-NPCC-1 needs to be considered to address the circumstance surrounding a design assessment that does not meet the performance characteristics as identified in Requirement R3 of PRC-006-1/PRC-006-2.

Revise Table 4 Attachment C to reflect the modified Quebec UFLS program parameters as recommended in the 2013 NPCC UFLS Adequacy Assessment and review the applicability of Requirements R4 and R5 as they pertain to the Quebec Interconnection.

Additionally, as identified by SS38 there are aspects of the performance requirements in NERC PRC-006-1 that are slightly more relaxed than the criteria in Directory#12 and these more stringent attributes of the NPCC criteria were not incorporated into the regional standard.

Specifically, the NPCC criteria in Directory#12 (Sections 5.1.1 and 5.1.2) state that (1) frequency decline is arrested at no less than 58.0 Hz for the portions of NPCC in the Eastern Interconnection, and 56.0 Hz for the portion of NPCC in the Quebec Interconnection (2) frequency should not remain below 59.5Hz for more than 30 seconds and should not remain below 58.5 Hz. for more than 10 seconds. Review the need to include the performance criteria presently in Directory#12 into PRC-006-NPCC-02, or whether the performance criteria included in PRC-006-1/PRC-006-2 is sufficient.

Interpretations of PRC-006-NPCC-1 to be considered to clarify PRC-006-NPCC-2.

The review will include an assessment of the need to include language to address dispersed generation resources.

PRC-006-NPCC-2 should be made to conform to the NERC Results Based Standard format.

After this review is completed, it will be determined if PRC-006-NPCC-1 should be revised, or retired.

Reliability Functions

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 Coordinator	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 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.
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.)

Review and compare regional standard PRC-006-NPCC-1with continent-wide standards PRC-006-1/PRC-006-2 and PRC-024-1/PRC-024-2 to determine if revisions are necessary, or retirement of PRC-006-NPCC-01 possible.

Determine the necessity for including wording to address dispersed generation resources.

Consider incorporating more stringent aspects of Directory#12 in order to facilitate future retirement of Directory#12.

Related Standards

Standard No.	Explanation
PRC-006-1/PRC-006-2	NERC Automatic Underfrequency Load shedding
PRC-024-1/PRC-024-2	NERC Generator Frequency and Voltage Protective Relay Settings

Related SARs or RSARs

SAR ID	Explanation

DRAFTING TEAM--RSAR PRC-006-NPCC-02

	Self-Nominations	
1	Dan Taft	Consolidated Edison Company of New York
2	Jonathan Appelbaum	The United Illuminating Company
3	Tim Kucey	PSEG Fossil LLC
4	Vincent Morissette	Hydro-Québec TransÉnergie
5	Dean Latulipe	National Grid
6	Brian Robinson--**RSAR Requester**	Utility Services, Inc.
7	Hamid Hamadani	Hydro One Networks, Inc.
8	Daniel Kidney	NPCC Compliance Staff
9	Ruida Shu	NPCC Standards Staff

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-2

3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. **Applicability:**

   4.1. Planning Coordinators

   4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

      4.2.1 Transmission Owners

      4.2.2 Distribution Providers

   4.3. Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. **Effective Date:**

   This standard is effective on the first day of the first calendar quarter six 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 calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   PRC-006-2 was developed under Project 2008-02: Underfrequency Load Shedding (UFLS). The drafting team revised PRC-006-1 for the purpose of addressing the directive issued in FERC Order No. 763. *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, 139 FERC ¶ 61,098 (2012).

B. Requirements and Measures

R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

2.1. Those islands selected by applying the criteria in Requirement R1, and

2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.

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]*

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 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.

M3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA

(gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.

R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: High][Time Horizon: Long-term Planning]*

- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

M5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.

R6. Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments 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]*

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per

Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.

R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the 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]*

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for implementation , including any Corrective Action Plan, per Requirement R9.

R10. Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, per Requirement R10.

R11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall

conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

R13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

M13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same

islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

M14. Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

R15. Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall develop a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area. *[VRF: High][Time Horizon: Long-term Planning]*

15.1. For UFLS design assessments performed under Requirement R4 or R5, the Corrective Action Plan shall be developed within the five-year time frame identified in Requirement R4.

15.2. For UFLS design assessments performed under Requirement R12, the Corrective Action Plan shall be developed within the two-year time frame identified in Requirement R12.

M15. Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall have a dated Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, that was developed within the time frame identified in Part 15.1 or 15.2.

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

Each Planning Coordinator and UFLS 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 Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, R14, and R15, Measures M1, M2, M3, M4, M5, M12, M14, and M15 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period 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

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.
R2	N/A	The Planning Coordinator identified an island(s) to	The Planning Coordinator identified an island(s) to serve	The Planning Coordinator identified an island(s) to serve

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3. OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.
R3	N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).,but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions. OR The Planning Coordinator failed to develop a UFLS program

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				including notification of and a schedule for implementation by UFLS entities within its area
R4	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.
R6	N/A	N/A	N/A	The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.
R7	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.
R8	The UFLS entity provided data to its Planning Coordinator(s) less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation,

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	program design and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.
R11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program,

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.	the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as specified in Requirement R11, Parts11.1 or 11.2.	conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				as specified in Requirement R11, Parts 11.1 and 11.2.
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13
R14	N/A	N/A	N/A	The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.
R15	N/A	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period of up to 1 month.	R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 1 month but not more than 2 months.	R3, but failed to develop a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area. OR The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 2 months.

D. Regional Variances

D.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

D.A.3. Each Planning Coordinator shall develop a UFLS program, including 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]*

D.A.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.A.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.A.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 associated with each of the following:

DA.3.3.1. Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

DA.3.3.2. Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

DA.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

M.D.A.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement D.A.3 Parts D.A.3.1 through DA3.3.

D.A.4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

D.A.4.1 Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1A, and

D.A.4.2 Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 - Attachment 1A, and

D.A.4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.D.A.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement D.A.4 Parts D.A.4.1 through D.A.4.3.

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
DA3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts D.A.3.1, D.A.3.2, and D.A.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
DA4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3 but simulation failed to include one (1) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D3 but simulation failed to include two (2) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D3 but simulation failed to include all of the items as specified in Parts D.A.4.1, D.A.4.2 and D.A.4.3. OR

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3

D.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

D.B.1. Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

M.D.B.1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement D.B.1.

D.B.2. Each Planning Coordinator shall identify one or more islands from the regional review (per D.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

D.B.2.1. Those islands selected by applying the criteria in Requirement D.B.1, and

D.B.2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System.

M.D.B.2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per D.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement D.B.2 Parts D.B.2.1 and D.B.2.2.

D.B.3. Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, 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]*

D.B.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

D.B.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

D.B.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 associated with each of the following:

D.B.3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

D.B.3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

D.B.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

M.D.B.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement D.B.3 Parts D.B.3.1 through D.B.3.3.

D.B.4. Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

D.B.4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

D.B.4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

D.B.4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation

above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

D.B.4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

D.B.4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

D.B.4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

D.B.4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.D.B.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement D.B.4 Parts D.B.4.1 through D.B.4.7.

D.B.11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

D.B.11.1. The performance of the UFLS equipment,

D.B.11.2 The effectiveness of the UFLS program

M.D.B.11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement D.B.11.

D.B.12. Each Planning Coordinator, in whose islanding event assessment (per D.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M.D.B.12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements D.B.12 and D.B.4 if UFLS program deficiencies are identified in D.B.11.

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.B.1	N/A	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands OR The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.B.2	N/A	N/A	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement D.B.2, Parts D.B.2.1 or D.B.2.2	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement D.B.2, Parts D.B.2.1 or D.B.2.2 OR The Planning Coordinator failed to identify any island(s) from the regional review to serve as a basis for designing its UFLS program.
D.B.3	N/A	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, or D.B.3.3 in	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, or D.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, and D.B.3.3 in

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		simulations of underfrequency conditions		simulations of underfrequency conditions OR The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.
D.B.4	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include one (1) of the items as specified in Requirement	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include two (2) of the items as specified in	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include three (3) of the items as specified in	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include four (4) or more of the items as

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	D.B.4, Parts D.B.4.1 through D.B.4.7.	Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.	Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.	specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7. OR The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2
D.B.11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.	evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement D.B.11, Parts D.B.11.1 or D.B.11.2.	evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2.
D.B.12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, failed to participate in

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies

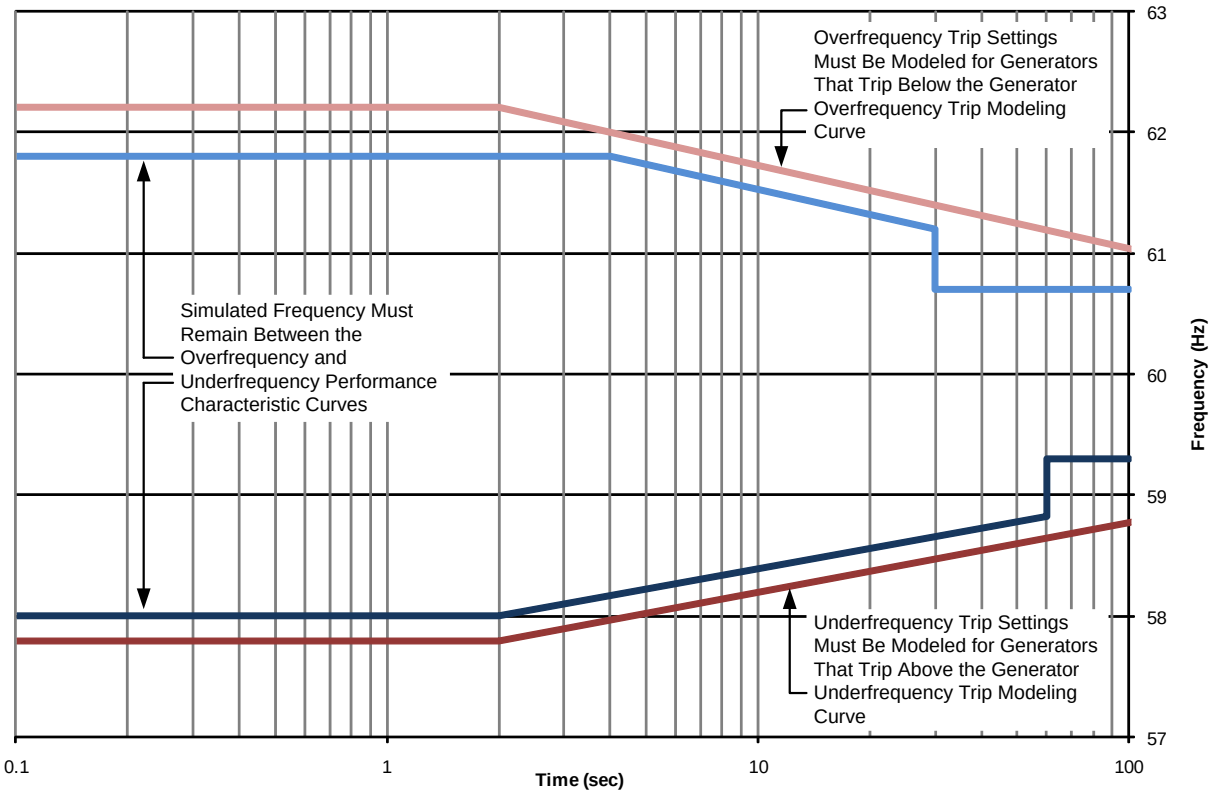
E. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 25, 2010	Completed revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0.	
1	November 4, 2010	Adopted by the Board of Trustees	
1	May 7, 2012	FERC Order issued approving PRC-006-1 (approval becomes effective July 10, 2012)	
1	November 9, 2012	FERC Letter Order issued accepting the modification of the VRF in R5 from (Medium to High) and the modification of the VSL language in R8.	
2	November 13, 2014	Adopted by the Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763. Revisions to existing Requirement R9 and R10 and addition of new Requirement R15.

PRC-006-2 – Attachment 1

Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



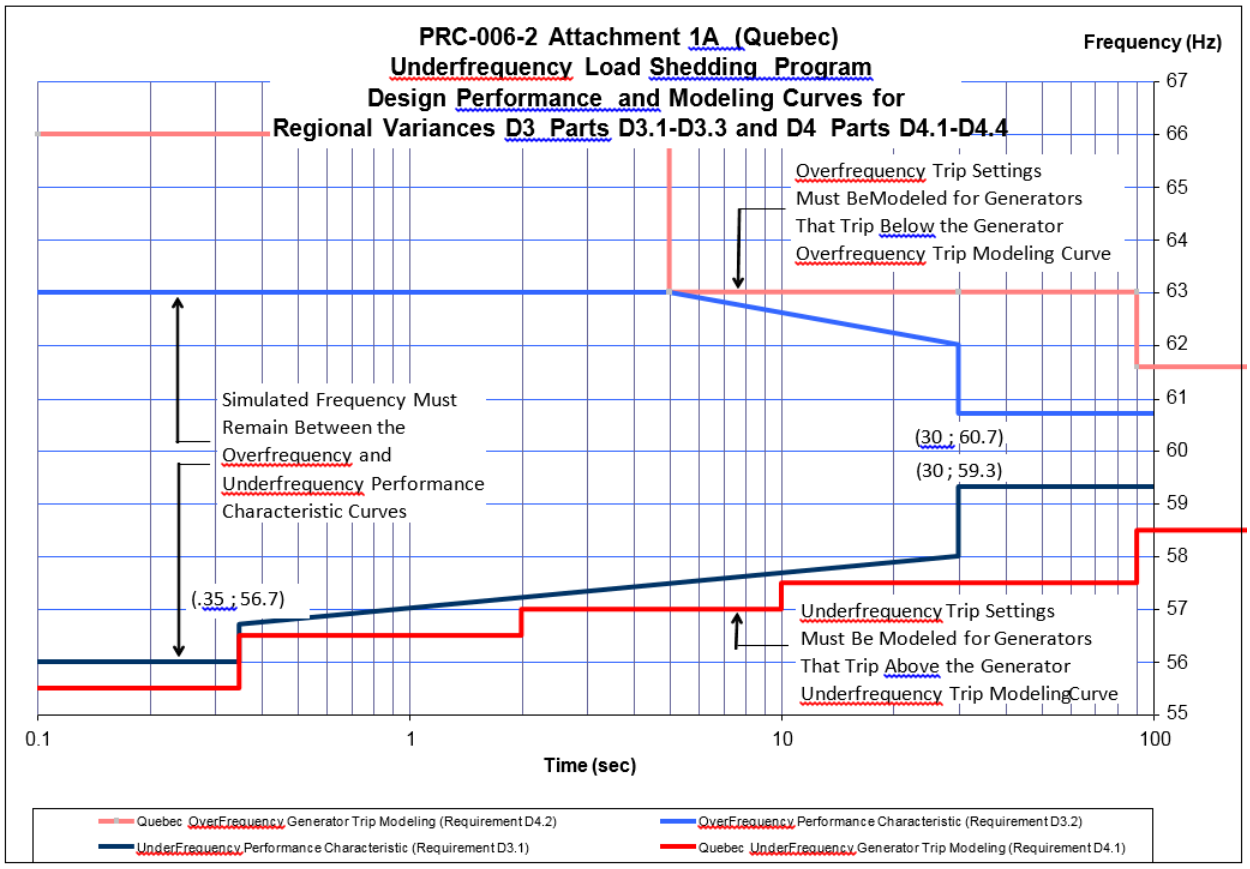
- Generator Overfrequency Trip Modeling (Requirement R4 Parts 4.4-4.6)
- Overfrequency Performance Characteristic (Requirement R3 Part 3.2)
- Underfrequency Performance Characteristic (Requirement R3 Part 3.1)
- Generator Underfrequency Trip Modeling (Requirement R4 Parts 4.1-4.3)

Curve Definitions

Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 4 s	4 s < t ≤ 30 s	t > 30 s
f = 62.2 Hz	f = -0.686log(t) + 62.41 Hz	f = 61.8 Hz	f = -0.686log(t) + 62.21 Hz	f = 60.7 Hz

Generator Underfrequency Trip Modeling	Underfrequency Performance Characteristic

t ≤ 2 s	t > 2 s	t ≤ 2 s	2 s < t ≤ 60 s	t > 60 s
f = 57.8 Hz	f = 0.575log(t) + 57.63 Hz	f = 58.0 Hz	f = 0.575log(t) + 57.83 Hz	f = 59.3 Hz


PRC-006-2 Attachment 1A (Quebec)
Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Regional Variances D3 Parts D3.1-D3.3 and D4 Parts D4.1-D4.4
Frequency (Hz)
67
66
65
64
63
62
61
60
59
58
57
56
55
Overfrequency Trip Settings
Must BeModeled for Generators
That Trip Below the Generator
Overfrequency Trip Modeling Curve
Simulated Frequency Must
Remain Between the
Overfrequency and
Underfrequency Performance
Characteristic Curves
(30 ; 60.7)
(30 ; 59.3)
(.35 ; 56.7)
Underfrequency Trip Settings
Must Be Modeled for Generators
That Trip Above the Generator
Underfrequency Trip ModelingCurve
0.1
1
10
100
Time (sec)
Quebec OverFrequency Generator Trip Modeling (Requirement D4.2)
OverFrequency Performance Characteristic (Requirement D3.2)
UnderFrequency Performance Characteristic (Requirement D3.1)
Quebec UnderFrequency Generator Trip Modeling (Requirement D4.1)

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 R9:

The "Corrective Action Plan" language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a Planning Coordinator (PC) assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word "application" was replaced with "implementation." (See Requirements R3, R14 and R15)

Rationale for R10:

The "Corrective Action Plan" language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word "application" was replaced with "implementation." (See Requirements R3, R14 and R15)

Rationale for R15:

Requirement R15 was added in response to the directive from FERC Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. Requirement R15 addresses the FERC directive by making explicit that if deficiencies are identified as a result of an assessment, the PC shall develop a Corrective Action Plan and schedule for implementation by the UFLS entities.

A "Corrective Action Plan" is defined in the NERC Glossary of Terms as, "a list of actions and an associated timetable for implementation to remedy a specific problem." Thus, the Corrective Action Plan developed by the PC will identify the specific timeframe for an entity to implement corrections to remedy any deficiencies identified by the PC as a result of an assessment.

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-NPCC-1

3. **Purpose:** To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics.

4. **Applicability:**

   4.1. Generator Owner

   4.2. Planning Coordinator

   4.3. Distribution Provider

   4.4. Transmission Owner

5. **Effective Date:** For the Eastern Interconnection & Québec Interconnection portions of NPCC excluding the Independent Electricity System Operator (IESO) Planning Coordinator area of NPCC in Ontario, Canada:

   The effective date for Requirements R1, R2, R3, R4, R5, R6, and R7 is the first day of the first calendar quarter following applicable regulatory approval but no earlier than January 1, 2016 The effective date for Requirements R8 through R23 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.

   For the Independent Electricity System Operator (IESO) Planning Coordinator's area of NPCC in Ontario, Canada:

   All requirements are effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017.

B. Requirements

R1 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]

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]

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]

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]

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]

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]

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 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]

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.

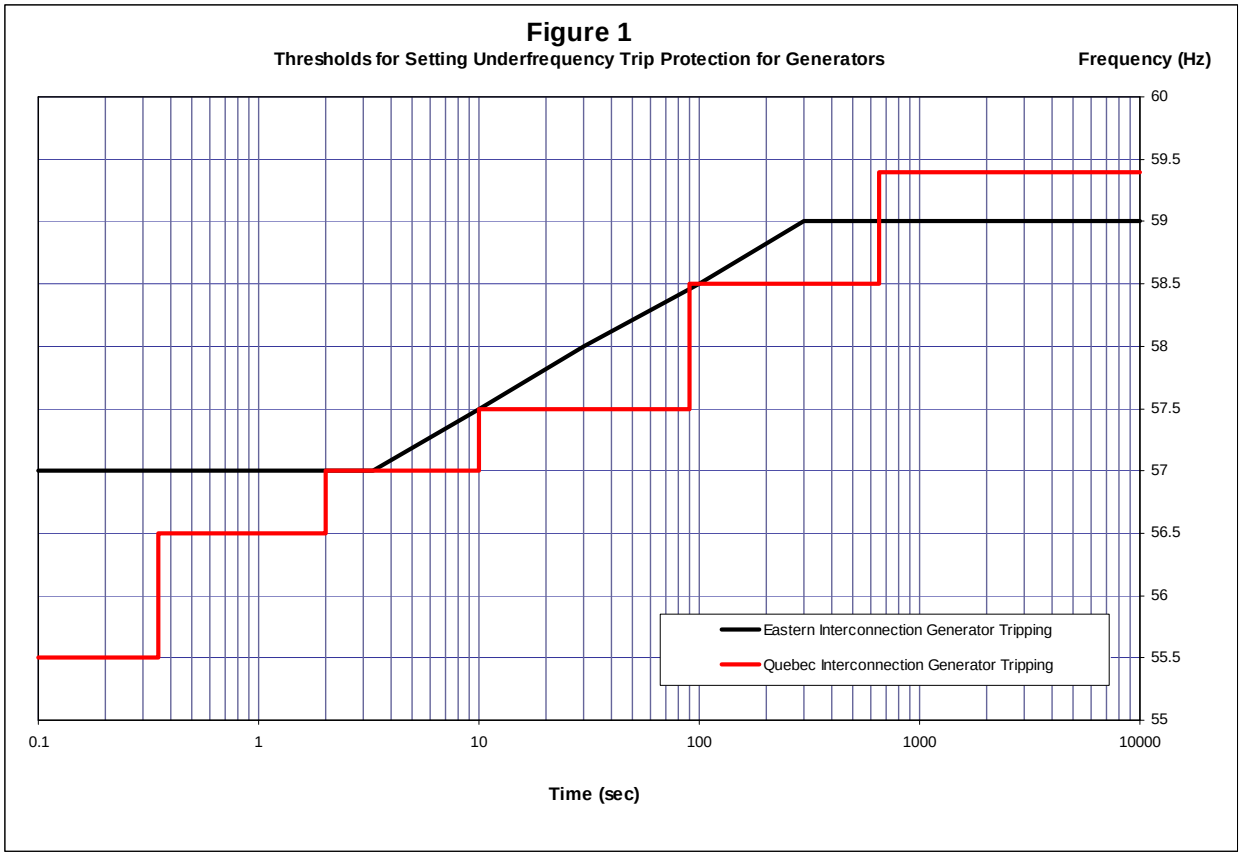
20.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

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]


Figure 1
Thresholds for Setting Underfrequency Trip Protection for Generators
Frequency (Hz)
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
0.1
1
10
100
1000
10000
Time (sec)
Eastern Interconnection Generator Tripping
Quebec Interconnection Generator Tripping

C. Measures

M1 Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

M3 Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

M4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4. (Attachment C Tables 1-3).

M5 Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

M6 Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R6. (Attachment C Table 4).

M7 Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R7.

M8 Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R8.

M9 Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

M10 Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R10.

M11 Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R11.

M12 Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R12.

M13 Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R13.

M14 Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R14.

M15 Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R15.

M16 Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R16.

M17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that

demonstrates that it followed the methodology described in Attachment A and meets Requirement R17.

M18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R18.

M19 Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R19.

M20 Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R20.

M21 Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R21.

M22 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R22.

M23 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement 23.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 4, 5, 6,7,10, 11, and 12.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 3, 8, 9, 20, and 21.

The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 17.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 18, 22, and 23.

The Generator Owner shall keep evidence for three calendar years for Measures 13, 14, 15, 16, and 19.

1.4. Compliance Monitoring and Assessment Processes

Self -Certifications.

Spot Checking.

Compliance Audits.

Self- Reporting.

Compliance Violation Investigations.

Complaints.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	**N/A**	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs. or Did not establish requirements for compensatory load shedding.	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs and did not establish requirements for compensatory load shedding.
R2	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 30 days but less than 41 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 40 days but less than 51 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 50 days but less than 61 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 60 days after completion of the system studies. or The Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program.
R3	The Planning Coordinator provided the requested information, but did so more than 30 days but less than 41 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 40 days but less than 51 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 50 days but less than 61 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 60 days after the request. or The Planning Coordinator failed to provide the requested

				information.
R4	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in the appropriate included tables.
R5	N/A	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not inform the Planning Coordinator of the need to exceed the stated	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not provide the Planning Coordinator with an analysis demonstrating that no alternative load shedding	The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load.

		tolerances of UFLS Table 2 or Table 3, and in the case of Table 2 only, the need to deviate from providing two stages of UFLS.	solution is available that would allow the Distribution Provider or Transmission Owner to comply with the appropriate table.	
R6	N/A	N/A	N/A	The Distribution Provider or Transmission Owner in the Québec Interconnection portion of NPCC did not implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or did not collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4.
R7	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to set

				an underfrequency relay that is part of its region's UFLS program as specified in Requirement R7.
R8	N/A	N/A	The Planning Coordinator developed inhibit thresholds as specified in Requirement R8 but did not perform the review once per calendar year.	The Planning Coordinator did not develop inhibit thresholds as specified in Requirement R8.
R9	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 days but less than 41 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 days but less than 51 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 days but less than 61 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 60 days after the initial determination or any subsequent change to the inhibit thresholds. or The Planning Coordinator did not provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds.
R10	N/A	N/A	N/A	The Distribution Provider or Transmission Owner did not implement the inhibit threshold based on the notification provided by the Planning Coordinator in accordance with

				Requirement R9.
R11	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider or Transmission Owner did not develop its implementation plan.
R12	N/A	N/A	N/A	The Transmission Owner or Distribution Provider did not provide documentation to its Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.
R13	N/A	N/A	N/A	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in

				Figure 1, except as otherwise exempted.
R14	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 45 days and less than 56 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 55 days and less than 66 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 65 days and less than 76 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 75days after the Planning Coordinator's request. or The Generator Owner did not transmit the generator underfrequency trip setting and time delay to its Planning Coordinator.
R15	N/A	N/A	The Generator Owner did not fulfill the obligation of Requirement R15; Part 15.1 OR did not fulfill the obligation of Requirement R15, Part 15.2.	The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.1 and did not fulfill the obligation of Requirement R15, Part 15.2.
R16	N/A	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.2.	The Generator Owner did not fulfill the obligation of Requirement R16; Part 16.1 OR did not fulfill the obligation of	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.1 and did not fulfill the obligation of

			Requirement R16, Part 16.3.	Requirement R16, Part 16.3.
R17	N/A	N/A	N/A	The Planning Coordinator did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required.
R18	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required.
R19	N/A	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.3.	The Generator Owner did not fulfill the obligation of Requirement R19; Part 19.1 OR did not fulfill the obligation of Requirement R19, Part 19.2.	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.1 and did not fulfill the obligation of Requirement R19, Part 19.2.
R20	The Planning Coordinator did not have data in its database for one of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for two of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for three of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for four or more of the parameters listed in Requirement 20, Parts 20.1 through 20.5.

R21	N/A	N/A	N/A	The Planning Coordinator did not notify a Distribution Provider, Transmission Owner, or Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements.
R22	N/A	N/A	N/A	The Distribution Provider, Transmission Owner, or Generator Owner did not implement the load distribution changes based on the notification provided by the Planning Coordinator.
R23	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider. Transmission Owner or Generator Owner did not develop its implementation plan.

Version History

Version	Date	Action	Change Tracking
1	November 20, 2011	Region BOD Approval	
1	February 9, 2012	Adopted by Board of Trustees	
1	February 21, 2013	Order issued by FERC approving PRC-006-NPCC-1 (approval effective April 29, 2013)	

PRC-006-NPCC-1 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 1. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements:

1. The Planning Coordinator shall identify, compile and maintain an updated list of all existing non-nuclear generating units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate, as identified in Requirement R1

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding.

    2.2 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4..

    2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 during an underfrequency event. If the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 does not correspond to a specific UFLS program stage threshold setting,

the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 1 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify and compile a list of all existing non-nuclear generating units in service prior to the effective date of this standard that has underfrequency protection set to trip above the appropriate curve in Figure 1. The list shall include the following information associated with each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 1, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment C

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:

Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
59.5	0.30	6.5 – 7.5	6.5 – 7.5
59.3	0.30	6.5 – 7.5	13.5 – 14.5
59.1	0.30	6.5 – 7.5	20.5 – 21.5
58.9	0.30	6.5 – 7.5	27.5 – 28.5
59.5	10.0	2 – 3	29.5 – 31.5

UFLS Table 2: Eastern Interconnection

Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time(s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	14-25	14-25
2	59.1	0.30	14-25	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 3: Eastern Interconnection

Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	28-50	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 4: Quebec Interconnection

	Rate	Frequency (Hz)	MW at peak (*Load must be fixed at all times when above 60% of peak load..)	Mvar at peak	Total Nominal Operating Time (s) [2]
Threshold Stage 1	——	58.5	1000*	1000	0.30
Threshold Stage 2	——	58.0	800*	800	0.30
Threshold Stage 3	——	57.5	800	800	0.30
Threshold Stage 4	——	57.0	800	800	0.30
Threshold Stage 5 (anti-stall)	——	59.0	500	500	20.0
Slope Stage 1	-0.3 Hz/s	58.5	400	400	0.30
Slope Stage 2	-0.4 Hz/s	59.8	800*	800	0.30
Slope Stage 3	-0.6 Hz/s	59.8	800*	800	0.30
Slope Stage 4	-0.9 Hz/s	59.8	800	800	0.30

2. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. The underfrequency relay operating time shall be measured from the time when the frequency passes through the frequency threshold set point.

NORTHEAST POWER COORDINATING COUNCIL, INC.
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October 31, 2016

Subject: Second Posting for Open Process Review of *PRC-006-03 Automatic Underfrequency Load Shedding Regional Quebec Variance.*

NPCC Full and General Members;

Please find attached clean and redlined versions of the draft NERC continent-wide PRC-006-3 Automatic Underfrequency Load Shedding standard which has been posted for a 45-day comment period through December 15, 2016.

The proposed changes reflect a revision to the existing PRC-006-2 Quebec Regional Variance.

Specifically, the "Section D. Regional Variance" and "Attachment 1A" which apply only to Quebec have been revised to reflect the unique nature of the Quebec interconnection.

Additionally, the revisions were developed in accordance with the NPCC Regional Standards Process Manual and have been endorsed by the NPCC Regional Standards Committee (RSC).

Also, attached are the *PRC-006-3 Automatic UFLS Regional Quebec Variance Implementation Plan, HQT Letter to Waive CEAP* and a comment form. Comments on the posted materials may be submitted through the NPCC Open Process Review, which may be accessed through: PRC-006-3 Automatic Underfrequency Load Shedding Regional Quebec Variance

Pending reconciliation of comments, the standard is scheduled to be posted for a 30-day pre-ballot review period with a subsequent ballot during the first quarter of 2017.

Please contact me with any questions regarding the Standard or this comment period.

Thank you.

Ruida Shu
Northeast Power Coordinating Council, Inc.
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Hydro Québec TransÉnergie

Une division d'Hydro-Québec

August 26, 2016

VIA EMAIL

Guy V. Zito
Assistant Vice-President Standards
NPCC
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Dupuis.Caroline@hydro.qc.ca

Subject: PRC-006-3 Automatic UFLS Québec Variance – CEAP Phase 2

Following the end of the comment period for PRC-006-3 Quebec variance on August 22, 2016 it is our understanding that the next step in the process toward adoption would normally be the second phase of the Cost Effective Analysis Process (CEAP). Considering that only the Quebec Interconnection is concerned by the changes in PRC-006-3 and that the proposed revision does not incur any additional costs for us since it reflects current planning criteria, Hydro-Québec TransÉnergie proposes to waive phase 2 of the CEAP. Please let us know if this is acceptable to NPCC.

Regards.

Caroline Dupuis, eng.
Manager of Reliability Standards and Regulatory Compliance
Direction Normes de fiabilité et conformité réglementaire
Direction principale – Contrôle des mouvements d'énergie et exploitation du réseau
Hydro-Québec TransÉnergie

c.c. Sylvain Clermont (HQT Director of Reliability Standards and Regulatory Compliance)
Patrick Doyle (HQT manager of SRPI, Direction Planification)
Jeannette Gauthier (member of PRC-006-3 SDT)
Vincent Morissette (SME and member of PRC-006-3 SDT)
Si Truc Phan (RSC contact for PRC-006-3)
Ruida Shu (NPCC coordinator for PRC-006-3)

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 Regional Standards Process Manager, NPCCstandard@npcc.org . The NPCC Regional Standards Process Manager 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:	PRC-006-3--Automatic Underfrequency Load Shedding – Variance for the Quebec Interconnection
Request Date:	June 2, 2015

RSAR Requester Information

Name:	Patrick Doyle Lee Pedowicz	**RSAR Type (Check box for one of these selections.)**	
Company:	Hydro-Québec TransÉnergie Northeast Power Coordinating Council, Inc. (NPCC)	☐	New Standard
Telephone:	1-514-879-4100 ext 5429 1-212-840-1070	☒	Revision to Existing Standard
Fax:	1-212-302-2782	☐	Withdrawal of Existing Standard
Email:	doyle.patrick@hydro.qc.ca lpedowicz@npcc.org	☐	Urgent Action

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

The purpose of this RSAR is to address the two problems mentioned below by modifying only those sections that are specific to the Quebec Interconnection (PRC-006-2 Section D. Regional Variances, Part D.A. Regional Variance for the Quebec Interconnection, and Attachment 1A (Quebec)). Revisions to the standard will ensure the continuity of System reliability in the Quebec Interconnection.

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

The industry need for this RSAR is to address two specific problems regarding UFLS requirements for the Quebec Interconnection :

1 - To meet the PRC-006-2 59.3 Hz requirement for scenarios where Quebec has a small generation deficiency (between 4 and 6 percent) those scenarios would require modifications to the current settings of the UFLS program to the threshold of 59.3 Hz which would cause unacceptable and frequent load shedding without any improvement to System reliability.

2 – Because the Quebec Interconnection itself is an island with unique generation characteristics and SPS applications, Section D.A.3 in PRC-006-2 needs to be revised to define a more accurate generation deficiency scenario applicable to the Quebec Interconnection.

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

A description of the two specific problems is as follows:

1 - The Quebec Interconnection has a low inertia compared to other Interconnections. This makes it subject to large frequency deviations during normal operation. Small generation deficiencies (4 to 6 percent) can lead to acceptable frequency deviations without triggering any UFLS thresholds, but still stabilize under a PRC-006-2 Attachment 1A performance curve. The scope of this SAR is to modify the performance curve in Attachment 1A to better reflect the design, performance, and modeling of the Quebec Interconnection and avoid unnecessary load shedding.

2 - The Quebec Interconnection is an island by itself and is the only island considered when performing the Quebec UFLS program assessment. No under-generated island can be created within the Quebec Interconnection. Under current planning and operational criteria, the largest generation deficiency scenarios are limited to the loss of the largest power plant not covered by a SPS. Using the peak case scenario, these generation deficiencies are far from the required 25%. Section D.A.3 should be revised to account for the characteristics of the Quebec Interconnection.

Reliability Functions

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 Coordinator	The responsible entity that assesses the longer-term reliability of its Planning Coordinator Area.
☐	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 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.
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.)

1 - Because of the characteristics of the Quebec Interconnection, 0.5-1.5 Hz frequency deviations resulting from small losses of generation occur frequently. The System is designed and operated such that these small generation losses are acceptable, do not pose any threat to System reliability, and do not lead to unnecessary automatic load shedding. The adjustment of the UFLS anti-stall threshold to meet the PRC-006-2 performance curve would cause frequent and unacceptable load shedding operations without any improvement to System reliability. This is clearly shown by recent UFLS program assessment studies, planning and operational studies, and the analysis of generation loss scenarios in the Quebec Interconnection.

During the 2014 assessment of the NPCC Underfrequency Load Shedding Program, studies showed that for small generation deficiencies (between 4 and 6 percent) in the Quebec Interconnection using the minimum spinning reserve requirement, the simulated frequency deviation does not meet the PRC-006-2 requirement of 59.3 Hz from Attachment 1A. However, further investigation determined that such scenarios result in acceptable frequency deviations without crossing any UFLS thresholds while stabilizing between the PRC-006-2 curve (59.3 Hz in Attachment 1A) and the upper UFLS (anti-stall) threshold (59.0 Hz) that is defined in PRC-006-NPCC-1 UFLS Table 4 - Quebec Interconnection. Meeting the PRC-006-2 59.3 Hz requirement for those scenarios would require modifications to the current settings of the UFLS program. The subsequent adjustment of the UFLS anti-stall threshold to 59.3 Hz would cause unacceptable and frequent load shedding without any gain to System reliability.

2 - The Quebec Interconnection is an island by itself and it is the only island considered when performing the Quebec UFLS program assessment. Due to the nature of the Quebec System's design (main generation centers located in the north, remote from the main load centers in the south), no other viable island with generating deficiencies can be created within the Quebec Interconnection. Under current planning and operational criteria, the largest generation deficiency scenarios are limited to the loss of the largest power plant not covered by a SPS. Assuming the Hydro-Quebec peak case scenarios, none of them would result in a 25% generation deficiency. To reach the 25 % criteria using a design (normal or extreme) contingency and viable island, a light load scenario was used while studying the loss of the largest power plant. This methodology is currently used in Hydro-Quebec and has been used since the JWG-2 Phase II (NPCC Joint Working Group for the review of adequacy of procedures for protection against off-nominal frequency operation) Report was published in 1993. However, further studies and investigations have shown that using the peak case scenario, the integrity of the Quebec Interconnection could not be preserved using a UFLS program for a 25% generation deficiency. Since there is no design contingency that can produce a generation deficiency of 25%, multiple extreme contingencies, such as the loss of more than one substation, need to be applied simultaneously on the peak case scenario in order to reach that level of generation deficiency. Using the peak load case scenario, these generation deficiencies do not meet the required 25%. Section D.A.3 should be revised to reflect the characteristics of

the Quebec Interconnection.

Related Standards

Standard No.	Explanation

Related SARs or RSARs

SAR ID	Explanation

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-~~2~~ 3

3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. **Applicability:**

   4.1. Planning Coordinators

   4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

   4.2.1 Transmission Owners

   4.2.2 Distribution Providers

   4.3. Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. **Effective Date:**

   This standard is effective on the first day of the first calendar quarter six 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 calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   PRC-006-2 was developed under Project 2008-02: Underfrequency Load Shedding (UFLS). The drafting team revised PRC-006-1 for the purpose of addressing the directive issued in FERC Order No. 763. *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, 139 FERC ¶ 61,098 (2012).

B. Requirements and Measures

R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

2.1. Those islands selected by applying the criteria in Requirement R1, and

2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.

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]*

3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-3~~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-006-3~~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 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.

M3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-3~~2~~ - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-3~~2~~ - Attachment 1.

4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-3~~2~~ - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-3~~2~~ — Attachment 1.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-3~~2~~ — Attachment 1.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-~~3~~2 — Attachment 1.

4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.

R5. Each Planning Coordinator, ~~-~~whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: High][Time Horizon: Long-term Planning]*

- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

M5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.

R6. Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments 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]*

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.

R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the 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]*

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for implementation~~.~~, including any Corrective Action Plan, per Requirement R9.

R10. Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, per Requirement R10.

R11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

R13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

M13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

M14. Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

R15. Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall develop a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area. *[VRF: High][Time Horizon: Long-term Planning]*

15.1. For UFLS design assessments performed under Requirement R4 or R5, the Corrective Action Plan shall be developed within the five-year time frame identified in Requirement R4.

15.2. For UFLS design assessments performed under Requirement R12, the Corrective Action Plan shall be developed within the two-year time frame identified in Requirement R12.

M15. Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall have a dated Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, that was developed within the time frame identified in Part 15.1 or 15.2.

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

Each Planning Coordinator and UFLS 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 Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, R14, and R15, Measures M1, M2, M3, M4, M5, M12, M14, and M15 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period 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

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.
R2	N/A	The Planning Coordinator identified an island(s) to	The Planning Coordinator identified an island(s) to serve	The Planning Coordinator identified an island(s) to serve

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3. OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.
R3	N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).,but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions. OR The Planning Coordinator failed to develop a UFLS program

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				including notification of and a schedule for implementation by UFLS entities within its area
R4	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.
R6	N/A	N/A	N/A	The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.
R7	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				other Planning Coordinators.
R8	The UFLS entity provided data to its Planning Coordinator(s) less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any Corrective Action Plan, as determined by the

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	Planning Coordinator(s) area in which it owns assets.
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.
R11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.	assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as specified in Requirement R11, Parts11.1 or 11.2.	evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13
R14	N/A	N/A	N/A	The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.
R15	N/A	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, and developed a Corrective Action Plan and a	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, and developed a Corrective Action Plan and a	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, but failed to develop a Corrective Action Plan and a

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period of up to 1 month.	schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 1 month but not more than 2 months.	schedule for implementation by the UFLS entities within its area. OR The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 2 months.

D. Regional Variances

D.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

Rationale for Requirement D.A.3:

There are two modifications for requirement D.A.3 :

1. 25% Generation Deficiency : Since the Quebec Interconnection has no potential viable BES Island in underfrequency conditions, the largest generation deficiency scenarios are limited to extreme contingencies not already covered by RAS.

Based on Hydro-Québec TransÉnergie Transmission Planning requirements, the stability of the network shall be maintained for extreme contingencies using a case representing internal transfers not expected to be exceeded 25% of the time.

The Hydro-Québec TransÉnergie defense plan to cover these extreme contingencies includes two RAS (RPTC- generation rejection and remote load shedding -and TDST - a centralized UVLS) and the UFLS.

2. Frequency performance curve (attachment 1A) : Specific cases where a small generation deficiency using a peak case scenario with the minimum requirement of spinning reserve can lead to an acceptable frequency deviation in the Quebec Interconnection while stabilizing between the PRC-006-2 requirement (59.3 Hz) and the UFLS anti-stall threshold (59.0 Hz).

An increase of the anti-stall threshold to 59.3 Hz would correct this situation but would cause frequent load shedding of customers without any gain of system reliability. Therefore, it is preferable to lower the steady state frequency minimum value to 59.0 Hz.

The delay in the performance characteristics curve is harmonized between D.A.3 and R.3 to 60 seconds.

Rationale for Requirements D.A.3.3. and D.A.4:

The **Q**uebec Interconnection has its own definition of BES. In Quebec, the vast majority of BES generating plants/facilities are not directly connected to the BES. For simulations to take into account sufficient generating resources D.A.3.3 and D.A.4 need simply refer to BES generators, plants or facilities since these are listed in a Registry approved by Québec's Regulatory Body (Régie de l'Énergie).

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D.A.3. 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)~~one of these extreme events:

- Loss of the entire capability of a generating station.
- Loss of all transmission circuits emanating from a generating station, switching station, substation or dc terminal.
- Loss of all transmission circuits on a common right-of-way.
- Three-phase fault with failure of a circuit breaker to operate and correct operation of a breaker failure protection system and its associated breakers.
- Three-phase fault on a circuit breaker, with normal fault clearing.
- The operation or partial operation of a RAS for an event or condition for which it was not intended to operate.

~~-~~ *[VRF: High][Time Horizon: Long-term Planning]*

D.A.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-~~3~~2 - Attachment 1A, either for ~~30~~ 60 seconds or until a steady-state condition between 59.~~3~~ 0 Hz and 60.7 Hz is reached, and

D.A.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-~~3~~2 - Attachment 1A, either for ~~30~~ 60 seconds or until a steady-state condition between 59.~~3~~ 0 Hz and 60.7 Hz is reached, and

D.A.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 Quebec BES generator bus and associated generator step-up transformer high-side bus ~~associated with each of the following:~~

~~**DA.3.3.1.** Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES~~

~~**DA.3.3.2.** Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES~~

~~**DA.3.3.3.** Facilities consisting of one or more units connected to~~ memorandums, e-mails, program plans, or other documentation of its UFLS

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program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement D.A.3 Parts D.A.3.1 through D.A.3.3.

M.D.A.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement D.A.3 Parts D.A.3.1 through D.A.3.3.

D.A.4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

D.A.4.1 Underfrequency trip settings of individual generating units that are part of Quebec BES plants/facilities ~~with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES~~ that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-32 - Attachment 1A, and

D.A.4.2 Overfrequency trip settings of individual generating units that are part of Quebec BES plants/facilities ~~with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES~~ that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-32 - Attachment 1A, and

D.A.4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.D.A.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement D.A.4 Parts D.A.4.1 through D.A.4.3.

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
DA3	N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts D.A.3.1, D.A.3.2, and D.A.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area.
DA4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined~~s~~ through dynamic simulation whether the UFLS program design ~~meets~~ met the performance characteristics in Requirement D.A.3 but the simulation failed to include one	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined~~s~~ through dynamic simulation whether the UFLS program design ~~meets~~ met the performance characteristics in Requirement D.A.3 but the simulation failed to include two	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined~~s~~ through dynamic simulation whether the UFLS program design ~~meets~~ met the performance characteristics in Requirement D.A.3 but the simulation failed to include all of

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
		(1) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.	(2) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.	the items as specified in Parts D.A.4.1, D.A.4.2 and D.A.4.3. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3

D.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

D.B.1. Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

M.D.B.1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement D.B.1.

D.B.2. Each Planning Coordinator shall identify one or more islands from the regional review (per D.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

D.B.2.1. Those islands selected by applying the criteria in Requirement D.B.1, and

D.B.2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System.

M.D.B.2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per D.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement D.B.2 Parts D.B.2.1 and D.B.2.2.

D.B.3. Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, 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]*

D.B.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-3~~2~~ - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.B.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-32 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.B.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 associated with each of the following:

D.B.3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

D.B.3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

D.B.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

M.D.B.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement D.B.3 Parts D.B.3.1 through D.B.3.3.

D.B.4. Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

D.B.4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-32 - Attachment 1.

D.B.4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-32 - Attachment 1.

D.B.4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation

above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-3~~2~~ - Attachment 1.

D.B.4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-3~~2~~ — Attachment 1.

D.B.4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-3~~2~~ — Attachment 1.

D.B.4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-3~~2~~ — Attachment 1.

D.B.4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.D.B.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement D.B.4 Parts D.B.4.1 through D.B.4.7.

D.B.11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

D.B.11.1. The performance of the UFLS equipment,

D.B.11.2 The effectiveness of the UFLS program

M.D.B.11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement D.B.11.

D.B.12. Each Planning Coordinator, in whose islanding event assessment (per D.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M.D.B.12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements D.B.12 and D.B.4 if UFLS program deficiencies are identified in D.B.11.

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.B.1	N/A	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands OR The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.B.2	N/A	N/A	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement D.B.2, Parts D.B.2.1 or D.B.2.2	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement D.B.2, Parts D.B.2.1 or D.B.2.2 OR The Planning Coordinator failed to identify any island(s) from the regional review to serve as a basis for designing its UFLS program.
D.B.3	N/A	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, or D.B.3.3 in simulations of underfrequency	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, or D.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, and D.B.3.3 in simulations of underfrequency

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		conditions		conditions OR The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.
D.B.4	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include one (1) of the items as specified in Requirement D.B.4, Parts D.B.4.1 through	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include two (2) of the items as specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include three (3) of the items as specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	D.B.4.7.			OR The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2
D.B.11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.	D.B.11.1 and D.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	D.B.11.1 and D.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement D.B.11, Parts D.B.11.1 or D.B.11.2.	D.B.11.1 and D.B.11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2.
D.B.12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, failed to participate in and document a coordinated UFLS design assessment of the

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies

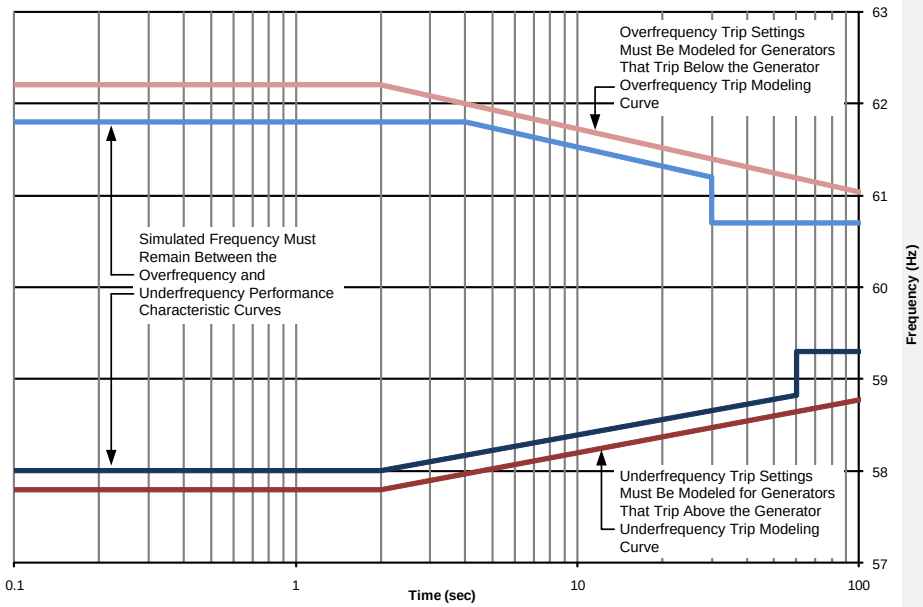
E. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 25, 2010	Completed revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0.	
1	November 4, 2010	Adopted by the Board of Trustees	
1	May 7, 2012	FERC Order issued approving PRC-006-1 (approval becomes effective July 10, 2012)	
1	November 9, 2012	FERC Letter Order issued accepting the modification of the VRF in R5 from (Medium to High) and the modification of the VSL language in R8.	
2	November 13, 2014	Adopted by the Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763. Revisions to existing Requirement R9 and R10 and addition of new Requirement R15.

PRC-006-~~2~~3 – Attachment 1

Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



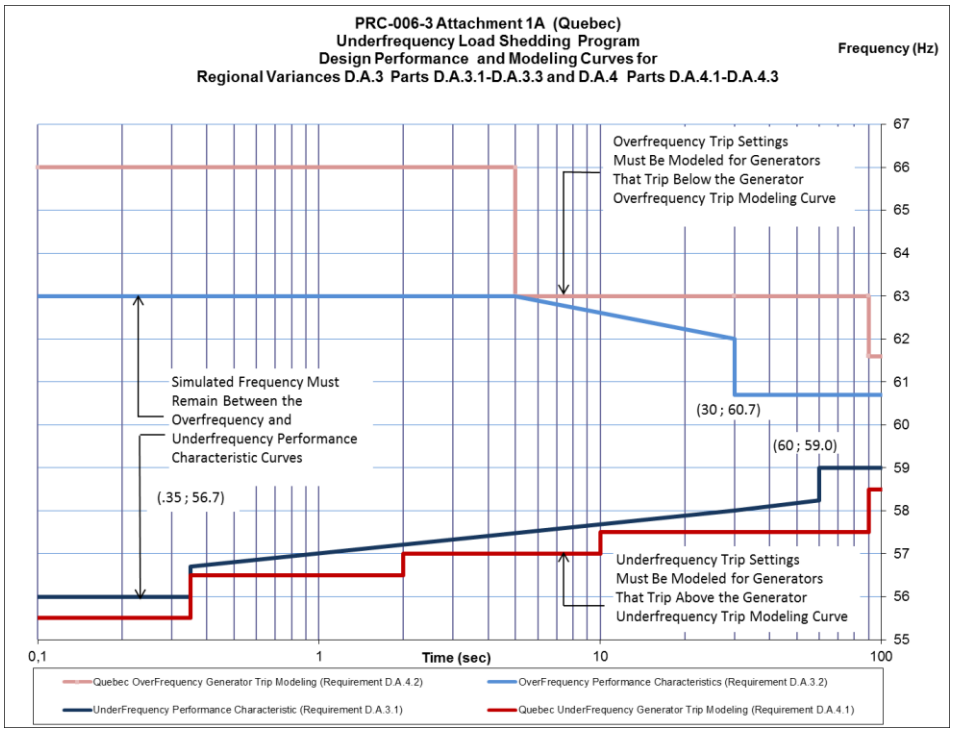
- Generator Overfrequency Trip Modeling (Requirement R4 Parts 4.4-4.6)
- Overfrequency Performance Characteristic (Requirement R3 Part 3.2)
- Underfrequency Performance Characteristic (Requirement R3 Part 3.1)
- Generator Underfrequency Trip Modeling (Requirement R4 Parts 4.1-4.3)

Curve Definitions

Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 4 s	4 s < t ≤ 30 s	t > 30 s
f = 62.2 Hz	f = -0.686log(t) + 62.41 Hz	f = 61.8 Hz	f = -0.686log(t) + 62.21 Hz	f = 60.7 Hz

Generator Underfrequency Trip Modeling	Underfrequency Performance Characteristic

t ≤ 2 s	t > 2 s	t ≤ 2 s	2 s < t ≤ 60 s	t > 60 s
f = 57.8 Hz	f = 0.575log(t) + 57.63 Hz	f = 58.0 Hz	f = 0.575log(t) + 57.83 Hz	f = 59.3 Hz


PRC-006-3 Attachment 1A (Quebec)
Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Regional Variances D.A.3 Parts D.A.3.1-D.A.3.3 and D.A.4 Parts D.A.4.1-D.A.4.3
Frequency (Hz)
Overfrequency Trip Settings
Must Be Modeled for Generators
That Trip Below the Generator
Overfrequency Trip Modeling Curve
Simulated Frequency Must
Remain Between the
Overfrequency and
Underfrequency Performance
Characteristic Curves
(.35 ; 56.7)
(30 ; 60.7)
(60 ; 59.0)
Underfrequency Trip Settings
Must Be Modeled for Generators
That Trip Above the Generator
Underfrequency Trip Modeling Curve
67
66
65
64
63
62
61
60
59
58
57
56
55
0,1
1
Time (sec)
10
100
Quebec OverFrequency Generator Trip Modeling (Requirement D.A.4.2)
OverFrequency Performance Characteristics (Requirement D.A.3.2)
UnderFrequency Performance Characteristic (Requirement D.A.3.1)
Quebec UnderFrequency Generator Trip Modeling (Requirement D.A.4.1)

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 R9:

The "Corrective Action Plan" language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a Planning Coordinator (PC) assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word "application" was replaced with "implementation." (See Requirements R3, R14 and R15)

Rationale for R10:

The "Corrective Action Plan" language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word "application" was replaced with "implementation." (See Requirements R3, R14 and R15)

Rationale for R15:

Requirement R15 was added in response to the directive from FERC Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. Requirement R15 addresses the FERC directive by making explicit that if deficiencies are identified as a result of an assessment, the PC shall develop a Corrective Action Plan and schedule for implementation by the UFLS entities.

A "Corrective Action Plan" is defined in the NERC Glossary of Terms as, "a list of actions and an associated timetable for implementation to remedy a specific problem." Thus, the Corrective Action Plan developed by the PC will identify the specific timeframe for an entity to implement corrections to remedy any deficiencies identified by the PC as a result of an assessment.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan (Draft for Comment)

Reliability Standard PRC-006-3 – Automatic Underfrequency Load Shedding

Revisions to Address Automatic Underfrequency Load Shedding (UFLS) Requirements for the Quebec Interconnection

Applicable Standard(s)

- PRC-006-3 – Automatic Underfrequency Load Shedding

Requested Retirement(s)

- PRC-006-2 – Automatic Underfrequency Load Shedding

Applicable Entities

- Planning Coordinators
- UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:
    - Transmission Owners
    - Distribution Providers
- Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators

Background

The PRC-006-3 Regional Standard Drafting Team revised Section D.A of PRC-006-2, Regional Variance for the Quebec Interconnection to address two specific problems regarding UFLS requirements for the Quebec Interconnection :

1. To meet the PRC-006-2 59.3 Hz requirement for scenarios where Quebec has a small generation deficiency (between 4 and 6 percent), those scenarios would require modifications to the current settings of the UFLS program to the threshold of 59.3 Hz; this would cause unacceptable and frequent load shedding without any improvement to System reliability.

2. Because the Quebec Interconnection itself is an island with unique generation characteristics and RAS (SPS) applications, Section D.A.3 in PRC-006-2 needs to be revised to define a more accurate generation deficiency scenario applicable to the Quebec Interconnection.

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Sector 7 – Sub-Regional Reliability Councils, Customers and Other Regional Entities and Interested Entities

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The continent-wide Requirements and all other aspects of the standard remain unchanged from PRC-006-2.

Effective Date

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 one month 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 one month after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard PRC-006-2 shall be retired immediately prior to the effective date of PRC-006-3 in the particular jurisdiction in which the revised standard is becoming effective.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

November 7, 2016

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

RE: Revisions to the Violation Risk Factors for Reliability Standards IRO-018-1 and TOP-010-1, Docket No. RD16-6-000

Dear Secretary Bose:

In accordance with the order issued by the Federal Energy Regulatory Commission ("Commission") on September 22, 2016 in the above-captioned docket,[1] and Section 320 of the North American Electric Reliability Corporation ("NERC")[2] Rules of Procedure,[3] NERC submits proposed revisions to the Violation Risk Factors ("VRFs") for Requirement R1 of Reliability Standard IRO-018-1 (*Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities*) and Requirements R1 and R2 of Reliability Standard TOP-010-1 (*Real-time Reliability Monitoring and Analysis Capabilities*). The revisions are attached hereto as Exhibit A.

On November 2, 2016, the NERC Board of Trustees approved the revised VRFs and authorized their submission to the Commission. NERC respectfully requests that the Commission approve the revised VRF designations as just, reasonable, not unduly discriminatory or preferential, in the public interest, and consistent with the Commission's directive in the September 22 Order.

[1] *Order Approving Reliability Standards*, 156 FERC ¶ 61,207 (2016) ("September 22 Order").

[2] The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the Federal Power Act on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

[3] NERC Rules of Procedure, Section 320, Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels, *available at* http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

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I. Background

As initially proposed, Reliability Standards IRO-018-1 and TOP-010-1 reflected "medium" VRF designations for all requirements. Support for these VRF designations was included in Section IV.D and Exhibit D of NERC's petition seeking approval of these Reliability Standards.[4]

In the September 22 Order, the Commission approved the Reliability Standards and the associated implementation plan, Violation Severity Levels, and several of the proposed VRFs. The Commission directed NERC to submit a compliance filing, within 60 days of the issuance of the September 22 Order, to revise the VRF designations for Requirement R1 of Reliability Standard IRO-018-1 and Requirements R1 and R2 of Reliability Standard TOP-010-1 from "medium" to "high".

II. Proposed VRF Revisions

Upon issuance of the September 22 Order, NERC reviewed the VRFs for Reliability Standards IRO-018-1 and TOP-010-1 pursuant to Section 320 of the NERC Rules of Procedure. The NERC director of standards recommended that the NERC Board of Trustees approve the Commission-directed revisions to the VRFs for these standards. On November 2, 2016, the NERC Board of Trustees approved submission of the revised VRFs (as Reliability Standards IRO-018-1(i) and TOP-010-1(i)), reflected in Exhibit A.

III. Conclusion

For the foregoing reasons, NERC respectfully requests that the Commission accept this filing and approve the proposed VRF revisions as just, reasonable, not unduly discriminatory or preferential, in the public interest, and compliant with the September 22 Order.

Respectfully submitted,

/s/ Lauren A. Perotti

Lauren A. Perotti
Counsel for North American Electric Reliability Corporation

cc: Official service list in Docket No. RD16-6-000

[4] *Petition of NERC for Approval of Proposed Reliability Standards IRO-018-1 and TOP-010-1*, Docket No. RD16-6-000, at Section IV.D and Exhibit D (filed May 26, 2016).

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 7th day of November, 2016.

/s/ Lauren A. Perotti

Lauren A. Perotti
Counsel for North American
Electric Reliability Corporation

EXHIBIT A

Reliability Standard IRO-018-1(i)

Clean and Redline

Reliability Standard IRO-018-1(i)

Clean Version

A. Introduction

1. **Title:** **Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities**

2. **Number:** **IRO-018-1(i)**

3. **Purpose:** Establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinators

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

1.1. Criteria for evaluating the quality of Real-time data;

1.2. Provisions to indicate the quality of Real-time data to the System Operator; and

1.3. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.

M1. Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R1; and 2) evidence the Reliability Coordinator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator or supporting logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R2. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments;

2.2. Provisions to indicate the quality of analysis used in its Real-time Assessments; and

2.3. Actions to address analysis quality issues affecting its Real-time Assessments.

M2. Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments as specified in Requirement R2. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R2; and 2) evidence the Reliability Coordinator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R3. Each Reliability Coordinator shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Reliability Coordinator shall have evidence of an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

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 it was compliant for the full-time period since the last audit.

The 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 Reliability Coordinator shall retain evidence of compliance for Requirements R1 and R3 and Measures M1 and M3 for the current calendar year and one previous calendar year, with the exception of operator logs and

voice recordings which shall be retained for a minimum of 90 calendar days, 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 retain evidence of compliance for Requirement R2 and Measure M2 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator is found non-compliant it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes 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 Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
R2.	N/A	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of

		analysis used in its Real-time Assessments did not include one of the elements listed in Part 2.1 through Part 2.3.	analysis used in its Real-time Assessments did not include two of the elements listed in Part 2.1 through Part 2.3.	analysis used in its Real-time Assessments did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments.
R3.	N/A	N/A	The Reliability Coordinator has an alarm process monitor but the alarm process monitor did not provide a notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	The Reliability Coordinator does not have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	October 30, 3015	New standard developed in Project 2009-02 to respond to recommendations in Real-time Best Practices Task Force Report and FERC directives.	N/A
1	May 5, 2016	Adopted by the Board of Trustees.	New
1	September 22, 2016	FERC Order issued approving IRO-018-1. Docket No. RD16-6-000	
1(i)	September 22, 2016	FERC directive to change Requirement 1 from 'medium' to 'high'. Docket No. RD16-6-000	Revised
1(i)	November 2, 2016	Adopted by the Board of Trustees	New

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by TOP and IRO Reliability Standards. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. Real-time monitoring may include the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

Requirement R1

The RC uses a set of Real-time data identified in IRO-010-1a Requirement R1 and IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Requirements to perform monitoring and Real-time Assessments appear in other Reliability Standards.

The RC's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed IRO-018-1 Requirement R1 Part 1.1. The criteria support identification of applicable data quality issues, which may include:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 specifies the RC shall include actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. Requirement R1 Part 1.3 is focused on addressing data point quality issues affecting Real-time Assessments. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R1 Part 1.3.

The RC's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the RC to meet its obligations for performing the Real-time Assessment. Examples of actions to address data quality issues include, but are not limited to, the following:

- Notifying entities that provide Real-time data to the RC;

- Following processes established for resolving data conflicts as specified in IRO-010-1a, IRO-010-2, or other applicable Reliability Standards;
- Taking corrective actions on the RC's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the RC's Real-time Assessment; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to address data quality issues in an appropriate timeframe.

Requirement R2

Requirement R2 ensures RCs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

Examples of the types of criteria used to evaluate the quality of analysis used in Real-time Assessments may include solution tolerances, mismatches with Real-time data, convergences, etc.

The Operating Process or Operating Procedure must describe how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

Requirement R3

Requirement R3 addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An alarm process monitor could be an application within a Real-time monitoring system or it could be a separate system. 'Heartbeat' or 'watchdog' monitors are examples of an alarm process monitor. An alarm process monitor should be designed and implemented such that a stall of the Real-time monitoring alarm processor does not cause a failure of the alarm process monitor.

Rationale

Rationale for Requirement R1: The Reliability Coordinator (RC) uses a set of Real-time data identified in IRO-010-1a Requirement R1 and IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Requirements to perform Real-time monitoring and Real-time Assessments appear in other Reliability Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 of this standard specifies the RC shall include actions to address Real-time data quality issues affecting its Real-time Assessments in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process used to resolve data conflicts required by IRO-010-2 Requirement R3 Part 3.2 provided that this process addresses Real-time data quality issues.

The revision in Part 1.3 to address Real-time data quality issues *when data quality affects Real-time Assessments* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

Rationale for Requirement R2: Requirement R2 ensures RCs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel. Operating personnel includes System Operators and staff responsible for supporting Real-time operations.

Rationale for Requirement R3: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

The requirement in Draft Two of the proposed standard has been revised for clarity by removing the term *independent*. The alarm process monitor must be able to provide notification of failure of the Real-time monitoring alarm processor. This capability could be provided by an application within a Real-time monitoring system or by a separate component used by the System Operator. The alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor.

Reliability Standard IRO-018-1(i)

Redline Version

A. Introduction

1. **Title:** **Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities**

2. **Number:** **IRO-018-1(i)**

3. **Purpose:** Establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinators

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: ~~Medium~~High] [Time Horizon: Real-time Operations]*

1.1. Criteria for evaluating the quality of Real-time data;

1.2. Provisions to indicate the quality of Real-time data to the System Operator; and

1.3. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.

M1. Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R1; and 2) evidence the Reliability Coordinator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator or supporting logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R2. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments;

2.2. Provisions to indicate the quality of analysis used in its Real-time Assessments; and

2.3. Actions to address analysis quality issues affecting its Real-time Assessments.

M2. Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments as specified in Requirement R2. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R2; and 2) evidence the Reliability Coordinator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R3. Each Reliability Coordinator shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Reliability Coordinator shall have evidence of an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

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 it was compliant for the full-time period since the last audit.

The 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 Reliability Coordinator shall retain evidence of compliance for Requirements R1 and R3 and Measures M1 and M3 for the current calendar year and one previous calendar year, with the exception of operator logs and

voice recordings which shall be retained for a minimum of 90 calendar days, 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 retain evidence of compliance for Requirement R2 and Measure M2 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator is found non-compliant it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes 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 Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
R2.	N/A	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of

		analysis used in its Real-time Assessments did not include one of the elements listed in Part 2.1 through Part 2.3.	analysis used in its Real-time Assessments did not include two of the elements listed in Part 2.1 through Part 2.3.	analysis used in its Real-time Assessments did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments.
R3.	N/A	N/A	The Reliability Coordinator has an alarm process monitor but the alarm process monitor did not provide a notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	The Reliability Coordinator does not have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	October 30, 3015	New standard developed in Project 2009-02 to respond to recommendations in Real-time Best Practices Task Force Report and FERC directives.	N/A
1	May 5, 2016	Adopted by the Board of Trustees.	New
1	September 22, 2016	FERC Order issued approving IRO-018-1. Docket No. RD16-6-000	
1(i)	September 22, 2016	FERC directive to change Requirement 1 from 'medium' to 'high'. Docket No. RD16-6-000	Revised
1(i)	November 2, 2016	Adopted by the Board of Trustees	New

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by TOP and IRO Reliability Standards. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. Real-time monitoring may include the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

Requirement R1

The RC uses a set of Real-time data identified in IRO-010-1a Requirement R1 and IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Requirements to perform monitoring and Real-time Assessments appear in other Reliability Standards.

The RC's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed IRO-018-1 Requirement R1 Part 1.1. The criteria support identification of applicable data quality issues, which may include:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 specifies the RC shall include actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. Requirement R1 Part 1.3 is focused on addressing data point quality issues affecting Real-time Assessments. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R1 Part 1.3.

The RC's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the RC to meet its obligations for performing the Real-time Assessment. Examples of actions to address data quality issues include, but are not limited to, the following:

- Notifying entities that provide Real-time data to the RC;

- Following processes established for resolving data conflicts as specified in IRO-010-1a, IRO-010-2, or other applicable Reliability Standards;
- Taking corrective actions on the RC's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the RC's Real-time Assessment; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to address data quality issues in an appropriate timeframe.

Requirement R2

Requirement R2 ensures RCs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

Examples of the types of criteria used to evaluate the quality of analysis used in Real-time Assessments may include solution tolerances, mismatches with Real-time data, convergences, etc.

The Operating Process or Operating Procedure must describe how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

Requirement R3

Requirement R3 addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An alarm process monitor could be an application within a Real-time monitoring system or it could be a separate system. 'Heartbeat' or 'watchdog' monitors are examples of an alarm process monitor. An alarm process monitor should be designed and implemented such that a stall of the Real-time monitoring alarm processor does not cause a failure of the alarm process monitor.

Rationale

Rationale for Requirement R1: The Reliability Coordinator (RC) uses a set of Real-time data identified in IRO-010-1a Requirement R1 and IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Requirements to perform Real-time monitoring and Real-time Assessments appear in other Reliability Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 of this standard specifies the RC shall include actions to address Real-time data quality issues affecting its Real-time Assessments in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process used to resolve data conflicts required by IRO-010-2 Requirement R3 Part 3.2 provided that this process addresses Real-time data quality issues.

The revision in Part 1.3 to address Real-time data quality issues *when data quality affects Real-time Assessments* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

Rationale for Requirement R2: Requirement R2 ensures RCs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel. Operating personnel includes System Operators and staff responsible for supporting Real-time operations.

Rationale for Requirement R3: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

The requirement in Draft Two of the proposed standard has been revised for clarity by removing the term *independent*. The alarm process monitor must be able to provide notification of failure of the Real-time monitoring alarm processor. This capability could be provided by an application within a Real-time monitoring system or by a separate component used by the System Operator. The alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor.

Reliability Standard TOP-010-1(i)

Clean and Redline

Reliability Standard TOP-010-1(i)

Clean Version

A. Introduction

1. **Title:** **Real-time Reliability Monitoring and Analysis Capabilities**
2. **Number:** **TOP-010-1(i)**
3. **Purpose:** Establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Transmission Operators
     - **4.1.2.** Balancing Authorities
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

- **1.1.** Criteria for evaluating the quality of Real-time data;
- **1.2.** Provisions to indicate the quality of Real-time data to the System Operator; and
- **1.3.** Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.

M1. Each Transmission Operator shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R1; and 2) evidence the Transmission Operator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R2. Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

- **2.1.** Criteria for evaluating the quality of Real-time data;
- **2.2.** Provisions to indicate the quality of Real-time data to the System Operator; and

2.3. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects its analysis functions.

M2. Each Balancing Authority shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R2; and 2) evidence the Balancing Authority implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R3. Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments;

3.2. Provisions to indicate the quality of analysis used in its Real-time Assessments; and

3.3. Actions to address analysis quality issues affecting its Real-time Assessments.

M3. Each Transmission Operator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments as specified in Requirement R3. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R3; and 2) evidence the Transmission Operator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R4. Each Transmission Operator and Balancing Authority shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. Each Transmission Operator and Balancing Authority shall have evidence of an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

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 it was compliant for the full-time period since the last audit.

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

The applicable entity shall retain evidence of compliance for Requirements R1, R2, and R4, and Measures M1, M2, and M4 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall retain evidence of compliance for Requirement R3 and Measure M3 for a rolling 30-day period, 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 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.

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 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 Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
R2.	N/A	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the

		Real-time data necessary to perform its analysis functions and Real-time monitoring did not include one of the elements listed in Part 2.1 through Part 2.3.	Real-time data necessary to perform its analysis functions and Real-time monitoring did not include two of the elements listed in Part 2.1 through Part 2.3.	Real-time data necessary to perform its analysis functions and Real-time monitoring did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Balancing Authority did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring.
R3.	N/A	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include one of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include two of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include any of the elements listed in Part 3.1 through Part 3.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of

				analysis used in its Real-time Assessments.
R4.	N/A	N/A	The responsible entity has an alarm process monitor but the alarm process monitor did not provide notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	The responsible entity does not have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	October 30, 2015	New standard developed in Project 2009-02 to respond to recommendations in Real-time Best Practices Task Force Report and FERC directives.	N/A
1	May 5, 2016	Adopted by the Board of Trustees	New
1	September 22, 2016	FERC Order issued approving TOP-010-1. Docket No. RD16-6-000	

1(i)	September 22, 2016	FERC directive to change Requirement 1 and Requirement 2 from 'medium' to 'high'. Docket No. RD16-6-000	Revised
1(i)	November 2, 2016	Adopted by the Board of Trustees	New

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by TOP and IRO Reliability Standards. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. Real-time monitoring may include the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

Requirement R1

The TOP uses a set of Real-time data identified in TOP-003-3 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Functional requirements to perform monitoring and Real-time Assessments appear in other Reliability Standards.

The TOP's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed TOP-010-1 Requirement R1 Part 1.1. The criteria support identification of applicable data quality issues, which may include:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 specifies the TOP shall include actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. Requirement R1 Part 1.3 is focused on addressing data point quality issues affecting Real-time Assessments. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R1 Part 1.3.

The TOP's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the TOP to meet its obligations for performing the Real-time Assessment. Examples of actions to address data quality issues include, but are not limited to, the following:

- Notifying entities that provide Real-time data to the TOP;
- Following processes established for resolving data conflicts as specified in TOP-003-3, or other applicable Reliability Standards;
- Taking corrective actions on the TOP's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the TOP's Real-time Assessment; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to address data quality issues in an appropriate timeframe.

Requirement R2

The BA uses a set of Real-time data identified in TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other Reliability Standards.

The BA's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed TOP-010-1 Requirement R2 Part 2.1. The criteria supports identification of applicable data quality issues, which may include:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R2 Part 2.3 specifies the BA shall include in its Operating Process or Operating Procedure actions to address Real-time data quality issues when data quality affects its analysis functions. Requirement R2 Part 2.3 is focused on addressing data point quality issues affecting analysis functions. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R2 Part 2.3.

The BA's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the BA to meet its obligations for performing its analysis functions. Examples of actions to address data quality issues include, but are not limited to, the following:

- Notifying entities that provide Real-time data to the BA;

- Following processes established for resolving data conflicts as specified in TOP-003-3 or other applicable Reliability Standards;
- Taking corrective actions on the BA's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the BA's analysis functions; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the analysis quality so that effective actions can be taken to address data quality issues in an appropriate timeframe.

Requirement R3

Requirement R3 ensures TOPs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments may include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

Examples of the types of criteria used to evaluate the quality of analysis used in Real-time Assessments may include solution tolerances, mismatches with Real-time data, convergences, etc.

The Operating Process or Operating Procedure must describe how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

Requirement R4

Requirement R4 addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An alarm process monitor could be an application within a Real-time monitoring system or it could be a separate system. 'Heartbeat' or 'watchdog' monitors are examples of an alarm process monitor. An alarm process monitor should be designed and implemented such that a stall of the Real-time monitoring alarm processor does not cause a failure of the alarm process monitor.

Rationale

Rationale for Requirement R1: The Transmission Operator (TOP) uses a set of Real-time data identified in TOP-003-3 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Functional requirements to perform Real-time monitoring and Real-time Assessments appear in other Reliability Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 of this standard specifies the TOP shall include actions to address Real-time data quality issues affecting its Real-time Assessments in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process used to resolve data conflicts required by TOP-003-3 Requirement R5 Part 5.2, provided that this process addresses Real-time data quality issues.

The revision in Part 1.3 to address Real-time data quality issues *when data quality affects Real-time Assessments* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

Rationale for Requirement R2: The Balancing Authority (BA) uses a set of Real-time data identified in TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other Reliability Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R2 Part 2.3 of this standard specifies the BA shall include actions to address Real-time data quality issues affecting its analysis functions in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process to resolve data conflicts required by TOP-003-3 Requirement R5 Part 5.2 provided that this process addresses Real-time data quality issues.

The revision in Part 2.3 to address Real-time data quality issues *when data quality affects its analysis functions* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

Rationale for Requirement R3: Requirement R3 ensures TOPs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state

estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel. Operating personnel includes System Operators and staff responsible for supporting Real-time operations.

Rationale for Requirement R4: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

The requirement in Draft Two of the proposed standard has been revised for clarity by removing the term *independent*. The alarm process monitor must be able to provide notification of failure of the Real-time monitoring alarm processor. This capability could be provided by an application within a Real-time monitoring system or by a separate component used by the System Operator. The alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor.

Reliability Standard TOP-010-1(i)

Redline Version

A. Introduction

1. **Title:** **Real-time Reliability Monitoring and Analysis Capabilities**
2. **Number:** **TOP-010-1(i)**
3. **Purpose:** Establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Transmission Operators
     - **4.1.2.** Balancing Authorities
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: ~~Medium~~High] [Time Horizon: Real-time Operations]*

- **1.1.** Criteria for evaluating the quality of Real-time data;
- **1.2.** Provisions to indicate the quality of Real-time data to the System Operator; and
- **1.3.** Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.

M1. Each Transmission Operator shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R1; and 2) evidence the Transmission Operator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R2. Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: ~~Medium~~High] [Time Horizon: Real-time Operations]*

- **2.1.** Criteria for evaluating the quality of Real-time data;
- **2.2.** Provisions to indicate the quality of Real-time data to the System Operator; and

2.3. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects its analysis functions.

M2. Each Balancing Authority shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R2; and 2) evidence the Balancing Authority implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R3. Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments;

3.2. Provisions to indicate the quality of analysis used in its Real-time Assessments; and

3.3. Actions to address analysis quality issues affecting its Real-time Assessments.

M3. Each Transmission Operator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments as specified in Requirement R3. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R3; and 2) evidence the Transmission Operator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R4. Each Transmission Operator and Balancing Authority shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. Each Transmission Operator and Balancing Authority shall have evidence of an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

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 it was compliant for the full-time period since the last audit.

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

The applicable entity shall retain evidence of compliance for Requirements R1, R2, and R4, and Measures M1, M2, and M4 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall retain evidence of compliance for Requirement R3 and Measure M3 for a rolling 30-day period, 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 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.

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 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 Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
R2.	N/A	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the

		Real-time data necessary to perform its analysis functions and Real-time monitoring did not include one of the elements listed in Part 2.1 through Part 2.3.	Real-time data necessary to perform its analysis functions and Real-time monitoring did not include two of the elements listed in Part 2.1 through Part 2.3.	Real-time data necessary to perform its analysis functions and Real-time monitoring did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Balancing Authority did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring.
R3.	N/A	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include one of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include two of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include any of the elements listed in Part 3.1 through Part 3.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of

				analysis used in its Real-time Assessments.
R4.	N/A	N/A	The responsible entity has an alarm process monitor but the alarm process monitor did not provide notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	The responsible entity does not have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	October 30, 2015	New standard developed in Project 2009-02 to respond to recommendations in Real-time Best Practices Task Force Report and FERC directives.	N/A
1	May 5, 2016	Adopted by the Board of Trustees	New
1	September 22, 2016	FERC Order issued approving TOP-010-1. Docket No. RD16-6-000	

1(i)	September 22, 2016	FERC directive to change Requirement 1 and Requirement 2 from 'medium' to 'high'. Docket No. RD16-6-000	Revised
1(i)	November 2, 2016	Adopted by the Board of Trustees	New

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by TOP and IRO Reliability Standards. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. Real-time monitoring may include the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

Requirement R1

The TOP uses a set of Real-time data identified in TOP-003-3 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Functional requirements to perform monitoring and Real-time Assessments appear in other Reliability Standards.

The TOP's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed TOP-010-1 Requirement R1 Part 1.1. The criteria support identification of applicable data quality issues, which may include:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 specifies the TOP shall include actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. Requirement R1 Part 1.3 is focused on addressing data point quality issues affecting Real-time Assessments. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R1 Part 1.3.

The TOP's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the TOP to meet its obligations for performing the Real-time Assessment. Examples of actions to address data quality issues include, but are not limited to, the following:

- Notifying entities that provide Real-time data to the TOP;
- Following processes established for resolving data conflicts as specified in TOP-003-3, or other applicable Reliability Standards;
- Taking corrective actions on the TOP's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the TOP's Real-time Assessment; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to address data quality issues in an appropriate timeframe.

Requirement R2

The BA uses a set of Real-time data identified in TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other Reliability Standards.

The BA's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed TOP-010-1 Requirement R2 Part 2.1. The criteria supports identification of applicable data quality issues, which may include:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R2 Part 2.3 specifies the BA shall include in its Operating Process or Operating Procedure actions to address Real-time data quality issues when data quality affects its analysis functions. Requirement R2 Part 2.3 is focused on addressing data point quality issues affecting analysis functions. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R2 Part 2.3.

The BA's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the BA to meet its obligations for performing its analysis functions. Examples of actions to address data quality issues include, but are not limited to, the following:

- Notifying entities that provide Real-time data to the BA;

- Following processes established for resolving data conflicts as specified in TOP-003-3 or other applicable Reliability Standards;
- Taking corrective actions on the BA's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the BA's analysis functions; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the analysis quality so that effective actions can be taken to address data quality issues in an appropriate timeframe.

Requirement R3

Requirement R3 ensures TOPs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments may include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

Examples of the types of criteria used to evaluate the quality of analysis used in Real-time Assessments may include solution tolerances, mismatches with Real-time data, convergences, etc.

The Operating Process or Operating Procedure must describe how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

Requirement R4

Requirement R4 addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An alarm process monitor could be an application within a Real-time monitoring system or it could be a separate system. 'Heartbeat' or 'watchdog' monitors are examples of an alarm process monitor. An alarm process monitor should be designed and implemented such that a stall of the Real-time monitoring alarm processor does not cause a failure of the alarm process monitor.

Rationale

Rationale for Requirement R1: The Transmission Operator (TOP) uses a set of Real-time data identified in TOP-003-3 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Functional requirements to perform Real-time monitoring and Real-time Assessments appear in other Reliability Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 of this standard specifies the TOP shall include actions to address Real-time data quality issues affecting its Real-time Assessments in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process used to resolve data conflicts required by TOP-003-3 Requirement R5 Part 5.2, provided that this process addresses Real-time data quality issues.

The revision in Part 1.3 to address Real-time data quality issues *when data quality affects Real-time Assessments* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

Rationale for Requirement R2: The Balancing Authority (BA) uses a set of Real-time data identified in TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other Reliability Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R2 Part 2.3 of this standard specifies the BA shall include actions to address Real-time data quality issues affecting its analysis functions in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process to resolve data conflicts required by TOP-003-3 Requirement R5 Part 5.2 provided that this process addresses Real-time data quality issues.

The revision in Part 2.3 to address Real-time data quality issues *when data quality affects its analysis functions* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

Rationale for Requirement R3: Requirement R3 ensures TOPs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state

estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel. Operating personnel includes System Operators and staff responsible for supporting Real-time operations.

Rationale for Requirement R4: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

The requirement in Draft Two of the proposed standard has been revised for clarity by removing the term *independent*. The alarm process monitor must be able to provide notification of failure of the Real-time monitoring alarm processor. This capability could be provided by an application within a Real-time monitoring system or by a separate component used by the System Operator. The alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

October 21, 2016

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 2016 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 attached Report provides an update to the statistical analyses and calculations contained in the 2012 Frequency Response Initiative Report included as Exhibit F to the March 29, 2013 NERC petition for approval of proposed Reliability Standard BAL-003-1, the 2014 Report submitted on March 20, 2015, and the 2015 Report submitted in this docket on December 16, 2015.[1]

In addition, the Report identifies inconsistencies in Interconnection Frequency Response Obligation ("IFRO") calculations under BAL-003-1.1 and recommends that the NERC Resources Subcommittee develop a Standard Authorization Request to address these issues. Due to these inconsistencies, discussed in the Findings section of the Report, IFRO values for operating year 2017 remain as calculated in 2015 for operating year 2016.[2] Frequency Response Obligations ("FROs") for individual Balancing Authorities will be allocated using 2015 generation and load data, as prescribed in BAL-003-1.1.

The attached Report also analyzes frequency events and interconnection frequency characteristics for the period January 1, 2012 through December 31, 2015, and determines the adjustment factors for calculating the IFROs using this data. This information is provided for consistency of the IFRO calculation, however, as noted above, the Report recommends that the IFRO values for operating year 2017 remain as calculated in 2015 for operating year 2016.[3]

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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).
2 *See, e.g.*, Report, at p. v.
3 *Id.*

Further, dynamic simulations of the Eastern, Western, and ERCOT Interconnections for the recommended IFROs showed those levels of primary Frequency Response to be adequate to avoid tripping of the first stage of the interconnection UFLS systems. Light-load cases were used for the analyses, as proposed in Paragraph 41 of the NOPR.[4] Evaluation of field trial data regarding the use of a linear regression method for calculating the Balancing Authority Frequency Response Measure is not included in the Report, but is continuing.

Moreover, as underscored in the NERC State of Reliability 2016 report, Frequency Response performance for all four interconnections from 2012 through 2015 exhibits stable trends.[5] As described in the Report, trend analysis showed improvement to frequency response recovery in the Eastern Interconnection with no other significant changes in trends. NERC will continue tracking frequency response performance across interconnections.[6]

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

[4] *Frequency Response and Frequency Bias Setting Reliability Standard*, Notice of Proposed Rulemaking, 144 FERC ¶ 61,057 (2013) "NOPR"); *and* Order No. 794, 146 FERC ¶ 61,024, P 84 (2014).

[5] *State of Reliability 2016 Report*, at p. 2 (May 2016), *available at*, http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2016_SOR_Report_Final_v1.pdf.

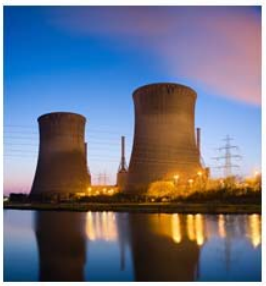
[6] *See, e.g.*, Report, at p. vi.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2016 Frequency Response Annual Analysis

September 2016

RELIABILITY | ACCOUNTABILITY



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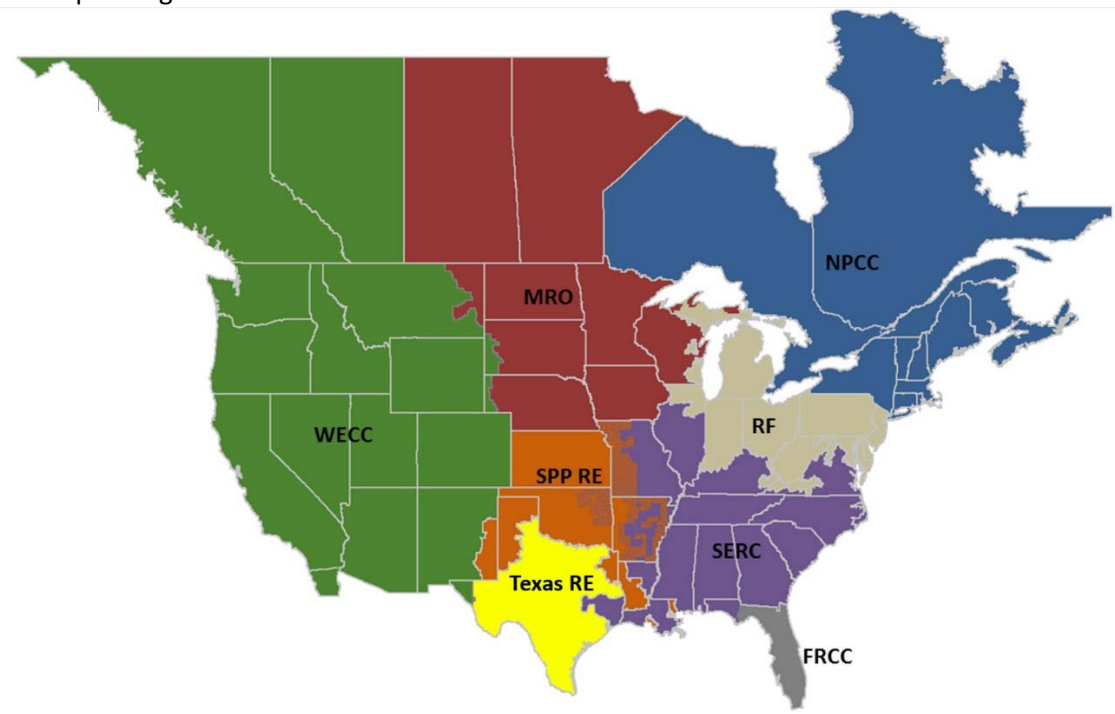
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Preface

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

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



The North American BPS is divided into eight Regional Entity (RE) boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

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

This Report

This report is the 2016 annual analysis of frequency response performance for the administration and support of NERC Reliability Standard BAL-003-1 – Frequency Response and Frequency Bias Setting. It provides an update to the statistical analyses and calculations contained in the *2012 Frequency Response Initiative Report* approved by the NERC Resources Subcommittee and Operating Committee and accepted by the NERC Board of Trustees. No changes are proposed to the procedures recommended in that report.

This report, prepared by NERC staff,[1] contains the analysis and annual recommendations for the calculation of the Interconnection Frequency Response Obligation (IFRO) for each of the four electrical interconnections of North America for the operational year 2017 (December 2016 through November 2017). This includes:

- Statistical analysis of the interconnection frequency characteristics for the period January 1, 2012, through December 31, 2015.[2]
- Calculation of adjustment factors from BAL-003-1 frequency response events.
- Dynamics analysis of the recommended IFROs.
- Analysis of frequency profiles for each interconnection.

This report was accepted by the Resources Subcommittee on August 25, 2016.

This report was accepted by the Operating Committee on September 30, 2016.

[1] Prepared jointly by the System Analysis and Performance Analysis departments.

[2] From the *2016 State of Reliability* report, available at: http://www.nerc.com/pa/RAPA/PA/Pages/default.aspx.

Executive Summary

Recommendations

The following recommendations provide the IFRO values following the IFRO formulae outlined as per BAL-003-1, as well as actions that should be taken to address inconsistencies in the IFRO calculation identified in this year's analysis. While the IFRO values are recommended to be frozen for operating year 2017 (December 2016 through November 2017), the IFRO values are also provided for reference.

In accordance with the BAL-003-1 detailed implementation plan (and as a condition of approval by the Resources Subcommittee and the Operating Committee), these analyses are performed annually and the results published by November 15 each year, starting in 2015.

Interconnection Frequency Response Obligation (IFRO)
The IFRO values are recommended to be fixed at the values calculated in the 2015 FRAA and currently in effect, until inconsistencies in the IFRO calculation outlined in this section are addressed.

The IFROs are considered to be the minimum frequency response necessary for the interconnections to maintain reliability and avoid tripping load by under frequency load shedding programs. It has no direct relationship to Frequency Bias setting used by Balancing Authorities to prevent withdrawal of primary frequency response by automatic generator control (AGC) action.

1. Due to inconsistencies outlined in the Findings section of this report, the IFRO values for operating year 2017 (December 2016 through November 2017) shall remain the same values as calculated in the 2015 FRAA report for operating year 2016, shown in Table A1.

Table A1: Recommended IFROs for Operating Year 2017

	Eastern (EI)	Western (WI)	Texas (TI)	Québec (QI)	Units
IFRO	**-1,015**	**-858**	**-381**	**-179**	**MW/0.1Hz**

2. The NERC Resources Subcommittee should develop a Standard Authorization Request (SAR) to revise the IFRO calculation in BAL-003-1 due to inconsistencies identified in the 2016 Frequency Response Annual Analysis (FRAA) such as the IFRO values with respect to Point C and varying Value B, the Eastern Interconnection Resource Contingency Protection Criteria, event selection criteria, and evaluation of t_0.
3. The Resource Contingency Protection Criteria for each interconnection should be revised to help ensure sufficient primary frequency response is maintained. The Eastern Interconnection uses the "largest resource event in last 10 years", which is the 4 August 2007 event. The Standard Authorization Request (SAR) should revisit this issue for modifications to BAL-003-1 standard, and the Resources Subcommittee should recommend how the events are selected for each interconnection.
4. Many events, particularly in the Eastern Interconnection due to its large synchronous inertia, tend to have a frequency nadir point that exceeds the t_0[3]+12 seconds specified in BAL-003-1. Therefore, some events are characterized with a Point C value that is only partially down the arresting period of the event and does not accurately reflect the actual nadir. BAL-003-1 should be modified to allow for accurate representation of the Point C nadir value if exceeding t_0+12 seconds. The actual event nadir can occur at any time, including beyond the time period used for calculating Value B (t_0+20 through t_0+52 seconds), and may be the value known as Point C' which typically occurs from 72 to 95 seconds after t_0.

[3] t_0 is defined as the time of the event.

1. The IFROs that were calculated for operating year 2017 (December 2016 through November 2017) are shown in Table A2. However, those values should NOT be used for operating year 2017, as noted in recommendation 1 and are provided here for reference (continuity of IFRO calculations for each year).

Table A2: Calculated IFROs for Operating Year 2017 using IFRO Formulae

	Eastern (EI)	Western (WI)	Texas (TI)	Québec (QI)	Units
Starting Frequency	59.974	59.967	59.967	59.968	Hz
Max. Allowable Delta Frequency	0.435	0.298	0.410	0.947	Hz
Resource Contingency Protection Criteria	4,500	2,626	2,750	1,700	MW
Credit for Load Resources	N/A	120	1,193	N/A	MW
IFRO	**-1,034**	**-841**	**-380**	**-179**	**MW/0.1Hz**
Absolute Value of IFRO	**1,034**	**841**	**380**	**179**	**MW/0.1Hz**
Absolute Value of Current Interconnection Frequency Response Performance[4]	2,424	1,344	690	610	MW/0.1Hz
2016 IFRO as a % of Interconnection Load[5]	0.170	0.526	0.532	0.469	

2. Frequency response withdrawal continues to be a predominant characteristic in the Eastern Interconnection, with 37 out of 84 events with a secondary nadir (Point C') lower than the initial frequency nadir (Point C). The BC'_{ADJ} adjustment factor introduced in the 2012 Frequency Response Initiative Report should continue to be tracked for the Eastern Interconnection.

3. Frequency response recovery phase (Value B) is improving in the Eastern Interconnection, with the CB_R ratio increasing by 0.019; however, there is no attendant improvement in Point C. This is indicative of success in the initiative to improve Eastern Interconnection primary frequency response of the conventional generator fleet. The ratio itself is still drastically lower than the other interconnections (1.071 for the Eastern Interconnection). In the Western Interconnection, the CB_R ratio decreased by 0.032; however, there are not significant trends in Value B or Point C and the ratio is still at 1.566. NERC should continue to track the characteristic shape of frequency response events for each interconnection in order to trend interconnection-wide performance of frequency in the recovery phase of the response.

4. The CB_R ratio in the IFRO calculation couples Point C and Value B together, resulting in IFRO trends that do not align with the intent of the standard. Improvement in Value B with no change in Point C (improving recovery phase) would result in higher obligation to be carried, essentially penalizing improved performance. This should be addressed as part of the revision of the IFRO calculation in the BAL-003-1 Reliability Standard.

[4] Based on Interconnection Frequency Response performance from Appendix E of the *2016 State of Reliability* report. By interconnection: EI = -2,424 MW / 0.1Hz, WI = -1,344 MW / 0.1Hz, TI = -690 MW / 0.1Hz, and QI = -610 MW/0.1 Hz.

[5] Draft Interconnection projected Total Internal Demands to be used in the *2016 NERC Long-Term Reliability Assessment* (2017 summer demand): EI = 609,946 MW, WI = 159,915 MW, TI = 71,416 MW, and QI (2016-2017 winter demand) = 38,150 MW. NOTE: These values are not finalized for the 2016 LTRA; draft numbers provided here for illustration purposes.

1. The NERC Resources Subcommittee (RS) should consider collecting data on individual unit performance for selected frequency response events to more comprehensively understand the frequency characteristics for each interconnection. This may include an assessment of the Eastern, Western, and Texas Interconnections. These efforts are intended to continue to improve primary frequency response.
2. In their dynamic case creation process, each interconnection should study the Resource Loss Protection Criteria contingency used by NERC for BAL-003-1 implementation to ensure that the simulation numerically converges[6]. NERC System Analysis worked with the case creation groups to mitigate errors in the dynamics cases prior to simulating the response; these numerical stability errors should not be present for the contingency under consideration. This may require the case creation entities in each interconnection to mitigate issues identified in some of the renewables models.

Findings

1. Analysis of the behavior of the IFRO calculations for each interconnection in response to trends in frequency response performance has identified inconsistencies in the IFRO calculation that need to be addressed immediately. Namely, the following findings are important to highlight:
   a. The ratio between Point C and Value B (CBR) is a multiplicative factor in the IFRO formulae, which couples these two quantities together in the formulation of the IFRO. Table A3 shows how the IFRO calculation will change based on relative movement of the differences between Value A and Point C and Value B (↑: increase, ↓: decrease, – : no change).

Table A3: IFRO Movement in Relation to Point C and Values A and B

Scenario	A-B	A-C	CB_R	IFRO
1	–	–	–	–
2	–	↑	↑	↑
3	↑	–	↓	↓
4	–	↓	↓	↓
5	↓	–	↑	↑
6	↑	↑	–	–
7	↓	↓	–	–

The original intent of the IFRO calculation was to ensure Scenario 2 was covered, where an increasing difference between Point A and the frequency nadir would result in an increased IFRO. However, the calculation also causes Scenarios 3 and 5 to have an adverse effect on the IFRO calculation. Scenario 3 is the situation where Value B is declining and results in a lower IFRO; conversely, Scenario 5 is the situation where Value B is improving (increasing) and results in a higher IFRO. The IFRO should not penalize an interconnection for better performance of frequency response measure against Value B nor reduce the obligation for poor performance.

   b. The statistically determined value for Starting frequency is important to account for a statistically determined value for which Point A can be assumed. However, the Delta Frequency should capture

[6] Does not cause any numerical issues due to problematic models.

an acceptable value of Point B that is based on historic trends of frequency nadir compared with Value B. This will ensure a decoupling of these values in the IFRO calculation.

2. The IFRO values calculated in this year's analysis compare closely with the IFRO values calculated in the 2015 FRAA; however, because of the inconsistencies identified in this analysis it is most appropriate to 'freeze' the IFRO values to those values currently in effect (2016 operating year as determined in the 2015 FRAA).
3. The University of Tennessee-Knoxville (UTK) FNET[7] data used in the analysis has seen significant improvement in data quality, greatly 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. This slightly modified data checking techniques resulted in no or minimal (+/- 0.001 Hz) change to starting frequency.
4. 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 because the actual frequency nadir was able to be accurately captured.
5. The Frequency Response Analysis Tool[8] (FRAT) is being used by the NERC Bulk Power System Awareness (BPSA) group for frequency event tracking in support of the NERC Frequency Working Group (FWG). The tool has significantly 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.
6. ERCOT underwent mid-year changes during the 2015 operating year for their process in procuring frequency-responsive load resources which are used to calculate their credit for load resources (CLR). In the Texas Interconnection IFRO calculation, CLR is based on a statistical analysis of procured CLR. Therefore, the changes are reflected in the statistically determined CLR calculation. CLR increased by 12 MW to 1,193 MW for the 2016 FRAA.
7. The ratio between Point C and Value B (CB_R) decreased in the Western Interconnection by -0.032 and increased in the Eastern Interconnection by 0.019. Trends in Point C and Value B for the Western Interconnection do not identify any noticeable trends in performance. Trends in the Eastern Interconnection show improved performance in Value B recovery period with no significant change in Point C (signifying improved governor response as an interconnection).
8. Dynamics simulations of the Eastern, Western, and Texas Interconnections for the recommended IFROs showed levels of primary frequency response to be adequate to avoid tripping of the first stage of the interconnection underfrequency load shedding (UFLS) systems. Light-load cases were used for all three of these analyses.

[7] 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.

[8] Developed by Pacific Northwest National Laboratory (PNNL).

Interconnection Frequency Characteristic Analysis

Frequency Variation Statistical Analysis

NERC staff performs a statistical analysis[9] annually of the variability of frequency for each of the four interconnections using a window of one-second-measured frequency. For this report's analysis, frequency data from 2012–2015 was used and is summarized in Table 1.

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.

One-Second Frequency Data
One-second frequency data for the frequency variation analysis is provided by 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.

Table 1: Interconnection Frequency Variation Analysis

Value	Eastern	Western	Texas	Québec
Time Frame (Operating Years)	2012-2015	2012-2015	2012-2015	2012-2015
Number of Samples	124,060,984	124,706,445	121,426,164	121,782,971
Filtered Samples (% of total)	98.3%	98.8%	96.2%	96.5%
Expected Value (Hz)	60.000	59.999	59.999	59.999
Variance of Frequency (σ^2)	0.00023	0.00036	0.00037	0.00037
Standard Deviation (σ)	0.01505	0.01895	0.01915	0.01936
50% percentile (median)	59.999	59.998	60.000	59.998
Starting Frequency (F_{start}) (Hz)	**59.974**	**59.967**	**59.967**	**59.968**

The starting frequencies encompass all variations in frequency including changes to the target frequency during TEC. This eliminates the need to expressly evaluate TEC as a variable in the IFRO calculation. The starting frequency for the calculation of IFROs is the 5th percentile lower tail of samples from the statistical analysis, which represents a 95 percent chance that frequencies will be at or above that value at the start of any frequency event.

Figures 1-4 show the probability density function of frequency for each interconnection. The vertical red line represents the 5th percentile frequency for each interconnection, representing the value at which interconnection frequency will statistically be greater than 95% of the time. A more detailed description of the probability density functions is provided in Appendix A.

[9] Refer to the 2012 *Frequency Response Initiative* report for details on the statistical analyses used.

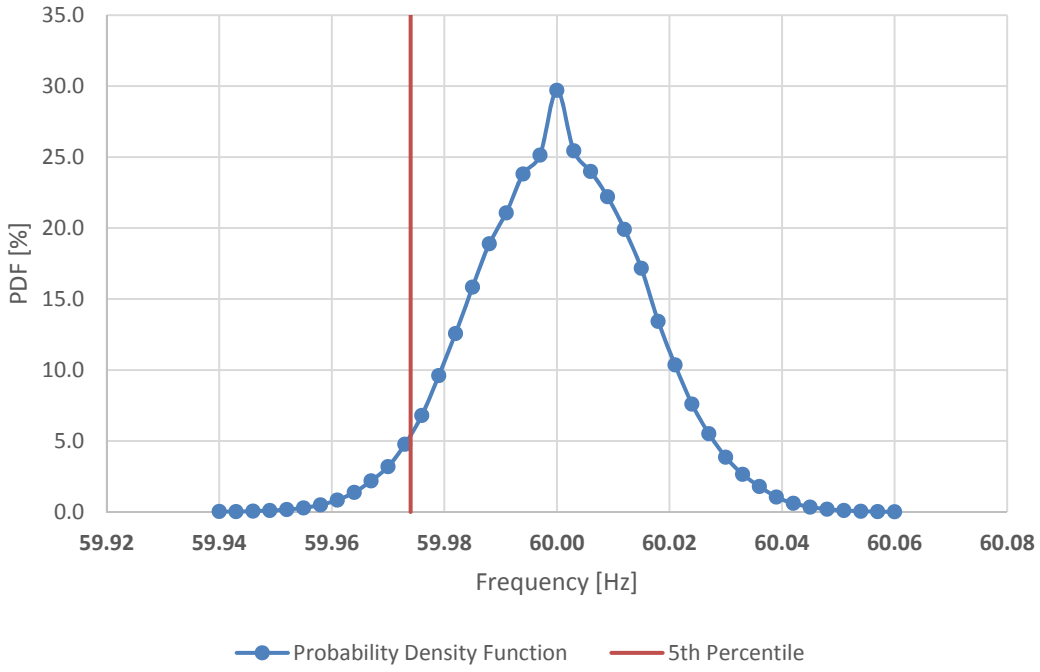


Figure 1: Eastern Interconnection 2012–2015 Probability Density Function of Frequency

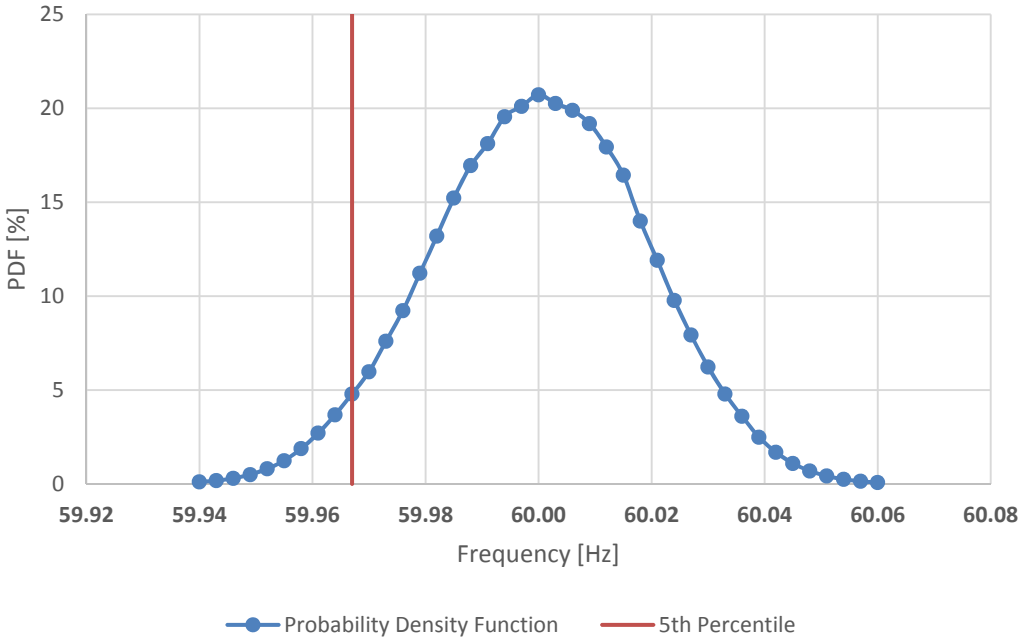


Figure 2: Western Interconnection 2012–2015 Probability Density Function of Frequency

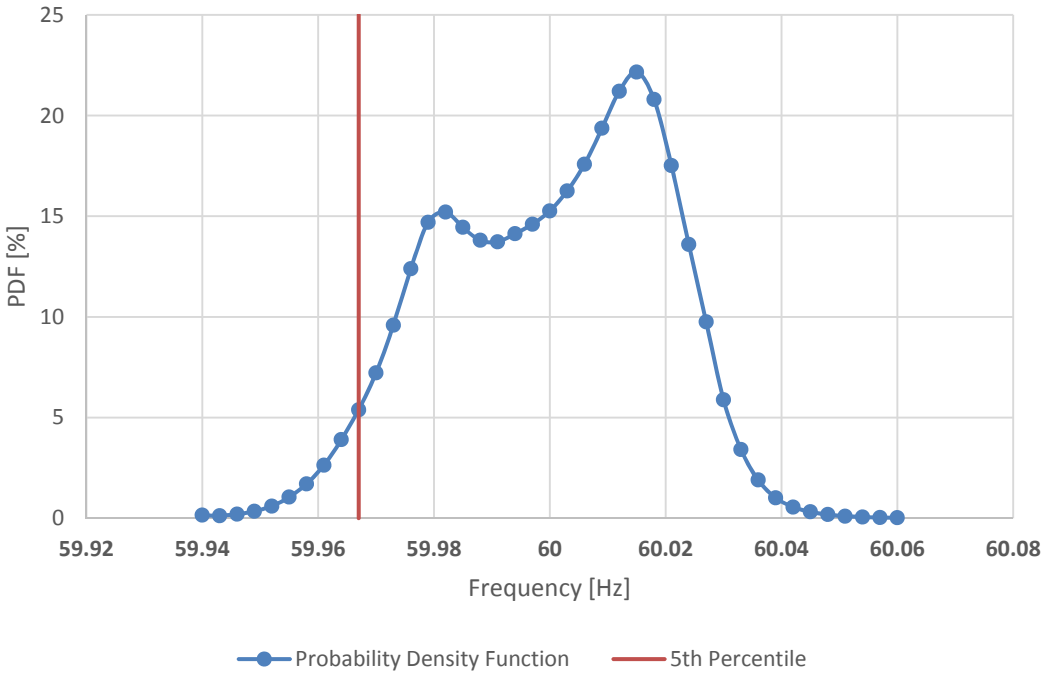


Figure 3: Texas Interconnection 2012–2014 Probability Density Function of Frequency

The probability density function of frequency for Texas has shown a dramatic change in 2015 when Standard TRE BAL-001 went into full effect in April of 2015. That standard requires all resources to provide primary frequency response with a ±16.7 mHz deadband with non-step, proportional response implementation. As a result, anytime frequency exceed 60.017 Hz, resources automatically curtail themselves. That has resulted in far less operation in frequencies above the deadband, since all resources, including wind, are backing down. This is exhibited in Figure 3 as a concentration of the probability density around the 60.017 Hz deadband and a reduction in the probability occurrences beyond that point. Similar behavior is not exhibited at the low deadband of 59.983 Hz because most wind resources are operated at maximum output and cannot increase when frequency falls below the deadband. Additional analysis of this change is contained in Appendix A.

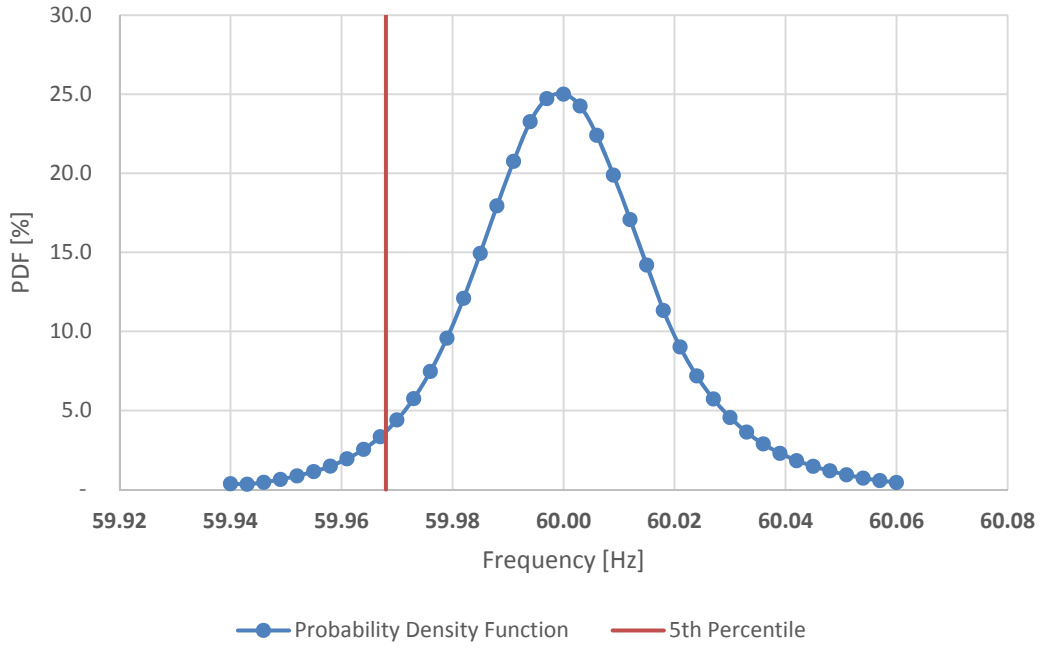


Figure 4: Québec Interconnection 2012–2014 Probability Density Function of Frequency

Changes in Starting Frequency

A comparison of expected frequencies and starting frequencies between the 2016 and 2015 frequency variability analyses is shown in Table 2. Expected frequencies are unchanged for all interconnections. Starting frequencies are unchanged for the Eastern and Western Interconnections; Texas and Québec Interconnections had a variation in starting frequencies of less than 0.001 Hz.

Table 2: Comparison of Interconnection Frequency Statistics (Hz)

	2015 Analysis	2016 Analysis	Change
Expected Frequencies			
Eastern	60.000	60.000	0.000
Western	59.999	59.999	0.000
Texas	59.999	59.999	0.000
Québec	59.999	59.999	0.000
Starting Frequencies			
Eastern	59.974	59.974	0.000
Western	59.967	59.967	0.000
Texas	59.966	59.967	0.001
Québec	59.969	59.968	-0.001

Determination of Interconnection Frequency Response Obligations

Tenets of IFRO

The IFRO is the minimum amount of frequency response that must be maintained by an interconnection. Each Balancing Authority in the interconnection should be allocated a portion of the IFRO that represents its minimum responsibility. To be sustainable, Balancing Authorities 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:

1. A frequency event should not trip the first stage of regionally approved UFLS systems within the interconnection.
2. Local tripping of first-stage UFLS systems for severe frequency excursions, particularly those associated with protracted faults or on systems on the edge of an interconnection, may be unavoidable.
3. Other frequency-sensitive loads or electronically coupled resources may trip during such frequency events, as is the case for photovoltaic (PV) inverters.
4. 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 violated for frequency events that happen on a relatively regular basis. As such, the resource loss protection criteria were selected through the Frequency Response Initiative 2012 analysis to avoid violating regionally approved UFLS settings.

IFRO Formulae

The following are the formulae that comprise the calculation of the IFROs:

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

$$DF_{CBR} = \frac{DF_{Base}}{CB_R}$$

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

$$ARLPC = RLPC - CLR$$

$$IFRO = \frac{ARLPC}{MDF}$$

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.
- RLPC is the resource loss protection criteria.
- CLR is the credit for load resources.
- ARLPC is the adjusted resource loss protection criteria adjusted for the credit for load resources.
- IFRO is the interconnection frequency response obligation.

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 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 Balancing Authority is limited to SCADA scan rates of one to six seconds. Therefore, the ability to measure frequency response at the Balancing Authority 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 between December 1, 2011 to November 30, 2015, which captures the relationship between Value B and Point C. This resulted in the number of events shown in Table 3.

Sub-Second Frequency Data Source
Frequency data used for calculating all of the adjustment factors used in the IFRO calculation comes from the UTK FNet system. Six minutes of data is used for each frequency disturbance analyzed, 1 minute prior to the event and 5 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 FDRs for that event.

Analysis Method

The IFRO is the minimum performance level that the Balancing Authorities 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 Balancing Authorities for the longer term. The ACE equation looks at the difference between scheduled frequency and actual frequency, times the Frequency Bias setting to estimate the amount of megawatts that are being provided by load and generation within the Balancing Authority. 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 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 pre-disturbance 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 3) should be used to compensate for the differences between Point C and Value B.

Table 3: 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	84	1.037	0.185	0.034	1.071
Western	60	1.525	0.192	0.041	1.566
Texas	155	1.576	0.372	0.050	1.626
Québec	102	3.964	1.000	0.164	1.550

The Eastern Interconnection exhibits a frequency response characteristic that often has Value B below Point C, and the CB_R value for the Eastern Interconnection has historically been below 1.000, therefore the CB_R has been limited to 1.000. However, the calculated CB_R in this year's analysis indicates a value above 1.000, and no limitation is required.

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 high rebound rates between Point C and the calculated Value B. For the 81 frequency events in their event sample, Québec's CB_R value would be 4.13, or 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.

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 the 2016 FRAA solely utilized sub-second measurements from FNET FDRs. Data at this resolution accurately reflect 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 nadir for a frequency event 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. For purposes of this report, the later-occurring nadir is termed Point C'. 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.

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.

Table 4 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 Point C for the period of January 2012 through December 2015. The statistical analysis is performed on the events with C' value lower than Value B to determine the adjustment factor BC'_{ADJ}.

Table 4: 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	84	54	37	0.006	0.004	0.007
Western	60	29	0	N/A	N/A	N/A
Texas	155	44	3	N/A	N/A	N/A
Québec	102	35	0	N/A	N/A	N/A

Although events with C' lower than C have been identified in the Texas Interconnection, there is only statistically significant data to apply this adjustment factor to the Eastern Interconnection. This will continue to be monitored moving forward to track these trends in C' performance. Therefore, a BC'_{ADJ} is only needed for the Eastern Interconnection; no BC'_{ADJ} is needed for the other three interconnections. The 95 percent quantile value is used for the Eastern Interconnection BC'_{ADJ} of 7 mHz (see Table 4) to account for the statistically expected Point C' value of a frequency event.

In the Eastern Interconnection, the Point C' nadir occurs 72-92 seconds after the start of the event[10] 90% of the time, which is well beyond the time frame for calculating Value B.

Low-Frequency Limit

The low-frequency limit to be used for the IFRO calculations should be the highest step in the interconnection for regionally approved UFLS systems.

[10] The timing of the C' occurrence is consistent with outer-loop plant and unit controls causing withdrawal of unit frequency response.

Table 5: Low-Frequency Limits (Hz)	
Interconnection	**Highest UFLS Trip Frequency**
Eastern	59.5
Western	59.5
Texas	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. Severe system conditions might drive the frequency and voltage to levels that present a combination of conditions to control systems that may cause some generation to trip. Severe rates-of-change occurring in voltage or frequency might actuate volts-per-hertz relays which would also trip some units. Similarly, some combustion turbines may not be able to sustain operation at frequencies below 59.5 Hz.

Electronically coupled resources may be susceptible to extremes in frequency. Laboratory testing by Southern California Edison of inverters used on residential and commercial scale 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 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 PV resources; however, IEEE Standard 1547 is being revised and will include significantly wider voltage ride-through capability.

Credit for Load Resources

The Texas Interconnection depends on contractually interruptible (an Ancillary Service) demand response that automatically trips at 59.7 Hz by underfrequency relay to help arrest frequency declines. A credit for load resources[11] (CLR) is made for the resource contingency for the Texas Interconnection.

The amount of CLR available 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 2014 through December 2015, similar to the approach used in the 2015 FRAA. Statistical analysis indicated that 1,193 MW of CLR is available 95 percent of the time. Therefore, a CLR adjustment of 1,193 MW is applied in the calculation of the Texas Interconnection IFRO as a reduction to the loss of resources.

The 2015 CLR for Texas Interconnection is only 12 MW higher than 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.

ERCOT Credit for Load Resources (CLR)
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 RRS.

[11] Formerly called Load acting as a Resource, or LaaR.

Determination of Maximum Allowable Delta Frequencies

Because of the measurement limitation 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 6 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:

- Adjustments for the differences between Point C and Value B.
- Adjustments for the event nadir being below Value C' (Eastern Interconnection only) due to primary frequency response withdrawal.

Table 6: Determination of Maximum Allowable Delta Frequencies

	Eastern	Western	Texas	Québec	Units
Starting Frequency	59.974	59.967	59.967	59.968	Hz
Minimum Frequency Limit	59.500	59.500	59.300	58.500	Hz
Base Delta Frequency	0.474	0.467	0.667	1.468	Hz
CB_R[12]	1.071	1.566	1.626	1.550	Ratio
Delta Frequency (DF_{CBR})[13]	0.443	0.298	0.410	0.947	Hz
BC'_{ADJ}[14]	0.007	N/A	N/A	N/A	Hz
Max. Allowable Delta Frequency	0.435	0.298	0.410	0.947	Hz

[12] Adjustment for the differences between Point C and Value B.
[13] DF_{CC}/CB_R
[14] Adjustment for the event nadir being below the Value B (Eastern Interconnection only) due to primary frequency response withdrawal.

Comparison of Maximum Allowable Delta Frequencies

The following is a comparison of the 2016 maximum allowable delta frequencies with the values from the 2015 *Frequency Response Annual Analysis* report.

Table 7a: Maximum Allowable Delta Frequency Comparison				
Eastern	**2015**	**2016**	**Change**	**Units**
Starting Frequency	59.974	59.974	0.000	Hz
Min. Frequency Limit	59.500	59.500	0.000	Hz
Base Delta Frequency	0.474	0.474	0.000	Hz
CC_{ADJ}	N/A	N/A	N/A	Hz
Delta Frequency (DF_{CC})	0.474	0.474	0.000	Hz
CB_R	1.052	1.071	0.019	Ratio
Delta Freq. (DF_{CBR})	0.450	0.443	-0.007	Hz
BC'_{ADJ}	0.007	0.007	0.000	Hz
Max. Allowable Delta Frequency	0.443	0.435	-0.007	Hz
Western	**2015**	**2016**	**Change**	**Units**
Starting Frequency	59.967	59.967	0.000	Hz
Min. Frequency Limit	59.500	59.500	0.000	Hz
Base Delta Frequency	0.467	0.467	0.000	Hz
CC_{ADJ}	N/A	N/A	N/A	Hz
Delta Frequency (DF_{CC})	0.467	0.467	0.000	Hz
CB_R	1.598	1.566	-0.032	Ratio
Delta Freq. (DF_{CBR})	0.292	0.298	0.006	Hz
BC'_{ADJ}	N/A	N/A	N/A	Hz
Max. Allowable Delta Frequency	0.292	0.298	0.006	Hz

In the Eastern Interconnection, the maximum allowable delta frequency value only changed by 7 mHz. The following are observations regarding maximum allowable delta frequency:

- CB_R increased from 1.052 to 1.071, and therefore the delta frequency (DF_{CBR}) decreased by 7 mHz. The increase in CB_R demonstrates a continued strength on Point C frequency nadir relative to Value B.
- BC'_{ADJ} remained the same between 2015 and 2016, illustrating some degree of continued governor response withdrawal.

In the Western Interconnection, the maximum allowable delta frequency value changed by 6 mHz. The following are observations regarding maximum allowable delta frequency:

- Delta frequency (DF_{CBR}) increased by 6 mHz due to the CB_R ratio decreasing by a factor of -0.032, illustrating a weaker Point C frequency nadir relative to Value B.

Table 7b: Maximum Allowable Delta Frequency Comparison				
Texas	**2015**	**2016**	**Change**	**Units**
Starting Frequency	59.966	59.967	0.001	Hz
Min. Frequency Limit	59.300	59.300	0.000	Hz
Base Delta Frequency	0.666	0.667	0.001	Hz
CC_{ADJ}	N/A	N/A	N/A	Hz
Delta Frequency (DF_{CC})	0.666	0.667	0.001	Hz
CB_R	1.619	1.626	0.007	Ratio
Delta Freq. (DF_{CBR})	0.411	0.410	-0.001	Hz
BC'_{ADJ}	N/A	N/A	N/A	Hz
Max. Allowable Delta Frequency	0.411	0.410	-0.001	Hz
Québec	**2015**	**2016**	**Change**	**Units**
Starting Frequency	59.969	59.968	-0.001	Hz
Min. Frequency Limit	58.500	58.500	0.000	Hz
Base Delta Frequency	1.469	1.468	-0.001	Hz
CC_{ADJ}	N/A	N/A	N/A	Hz
Delta Frequency (DF_{CC})	1.469	1.468	-0.001	Hz
CB_R	1.550	1.550	0.000	Ratio
Delta Freq. (DF_{CBR})	0.948	0.947	-0.001	Hz
BC'_{ADJ}	N/A	N/A	N/A	Hz
Max. Allowable Delta Frequency	0.948	0.947	-0.001	Hz

In the Texas Interconnection, the maximum allowable delta frequency value changed by 1 mHz. The following are observations regarding maximum allowable delta frequency:

- The CB_R factor increased by 0.007, and therefore the delta frequency (DF_{CBR}) only decreased by 1 mHz.

In the Québec Interconnection, the maximum allowable delta frequency value changed by 1 mHz.

Calculated IFROs

Table 8 shows the determination of IFROs for operating year 2017 (December 2016 through November 2017) 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 8: Recommended IFROs

	Eastern (EI)	Western (WI)	Texas (TI)	Québec (QI)	Units
Starting Frequency	59.974	59.967	59.967	59.968	Hz
Max. Allowable Delta Frequency	0.435	0.298	0.410	0.947	Hz
Resource Contingency Protection Criteria	4,500	2,626	2,750	1,700	MW
Credit for Load Resources	N/A	120[15]	1,193	N/A	MW
IFRO	**-1,034**	**-841**	**-380**	**-179**	**MW/0.1Hz**
Absolute Value of IFRO[16]	**1,034**	**841**	**380**	**179**	**MW/0.1Hz**
Absolute Value of Current Interconnection Frequency Response Performance[17]	2,424	1,344	690	610	MW/0.1Hz
2016 IFRO as a % of Interconnection Load[18]	0.170	0.526	0.532	0.469	

[15] Based on the most updated information regarding load shedding for loss of 2 Palo Verde units, Western Interconnection CLR = 120 MW.

[16] The values of IFRO calculated here for the 2016 FRAA are shown for reference. It is recommended that the IFROs for operating year 2017 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.

[17] Based on Interconnection Frequency Response performance from Appendix E of the *2016 State of Reliability* report. By interconnection: EI = -2,424 MW / 0.1Hz, WI = -1,344 MW / 0.1Hz, TI = -690 MW / 0.1Hz, and QI = -610 MW/0.1 Hz.

[18] Draft Interconnection projected Total Internal Demands to be used in the *2016 NERC Long-Term Reliability Assessment* (2017 summer demand): EI = 609,946 MW, WI = 159,915 MW, TI = 71,416 MW, and QI (2016-2017 winter demand) = 38,150 MW. NOTE: These values are not finalized for the 2016 LTRA; draft numbers provided here for illustration purposes.

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. The following is a comparison of the current IFROs and their key component values to those presented in the 2014 *Frequency Response Annual Analysis* report.

Table 9a: Interconnection IFRO Comparison

Eastern	2015	2016	Change	Units
Starting Frequency	59.974	59.974	0.000	Hz
Max. Allowable Delta Frequency	0.443	0.435	-0.007	Hz
Resource Contingency Protection Criteria	4,500	4,500	0	MW
Credit for LR	N/A	N/A	N/A	MW
Absolute Value of IFRO	1,015	1,034	19	MW/0.1Hz
Western	**2015**	**2016**	**Change**	**Units**
Starting Frequency	59.967	59.967	0.000	Hz
Max. Allowable Delta Frequency	0.292	0.298	0.006	Hz
Resource Contingency Protection Criteria	2,626	2,626	0	MW
Credit for LR	120	120	0	MW
Absolute Value of IFRO	858	841	-17	MW/0.1Hz

The IFRO for the Eastern Interconnection increased by 19 MW/0.1 Hz, reflecting a slight change to frequency response characteristic. This is predominantly due to an increase in the ratio between Point C frequency nadir and Value B settling frequency.

The IFRO for the Western Interconnection decreased by 17 MW/0.1 Hz. Frequency response characteristic experienced a decrease in the ratio between Point C frequency nadir and Value B settling frequency, which will increase the maximum allowable delta frequency and hence the IFRO.

Table 9b: Interconnection IFRO Comparison				
Texas	**2015**	**2016**	**Change**	**Units**
Starting Frequency	59.966	59.967	0.001	Hz
Max. Allowable Delta Frequency	0.411	0.410	-0.001	Hz
Resource Contingency Protection Criteria	2,750	2,750	0	MW
Credit for LR	1,181	1,193	12	MW
Absolute Value of IFRO	381	380	-1	MW/0.1Hz
Québec	**2015**	**2016**	**Change**	**Units**
Starting Frequency	59.969	59.968	-0.001	Hz
Max. Allowable Delta Frequency	0.948	0.947	-0.001	Hz
Resource Contingency Protection Criteria	1,700	1,700	0	MW
Credit for LR	N/A	N/A	N/A	MW
Absolute Value of IFRO	179	179	0	MW/0.1Hz

The IFRO for the Texas Interconnection decreased by only 1 MW/0.1 Hz, representing a relatively stable frequency response characteristic over the time period of events analyzed.

The Québec Interconnection IFRO did not change, also representing a relatively stable frequency response characteristic over the time period of events analyzed.

Dynamics Analysis of Recommended IFROs

Off-peak dynamics analysis was performed of the recommended IFROs for the Eastern, Western, and Texas Interconnections to determine if those levels of primary frequency response are adequate to avoid tripping of the first stage of regionally approved UFLS systems in the interconnection. Light load cases prepared by each of the interconnections were used as the starting root case for the analyses. In each case, the dynamic governor or load responses were tuned until the primary frequency response of the interconnection closely matched the recommended IFRO value for the prescribed resource loss. In all three simulations, the effects of automatic generation control (AGC), which typically starts to influence frequency response in the 30-45 second timeframe, were not modeled.

In all three interconnections analyzed, frequency remained above the highest UFLS set point even with Interconnection frequency response degraded to the IFRO value.

Eastern Interconnection

For the Eastern Interconnection, the 2016 light load case developed by MMWG[19] for frequency response analysis was used as the starting root case. This case is supposed to more accurately represent actual governor settings, particularly related to governor response and squelched response. Figure 5 shows two figures. The figure on the left is the simulation of the resource loss protection criteria contingency with the case as-is. As the plot shows, the case did not converge for this relatively large contingency. The figure on the right shows the simulation results after working with the case to get it to converge for the duration of the simulation.

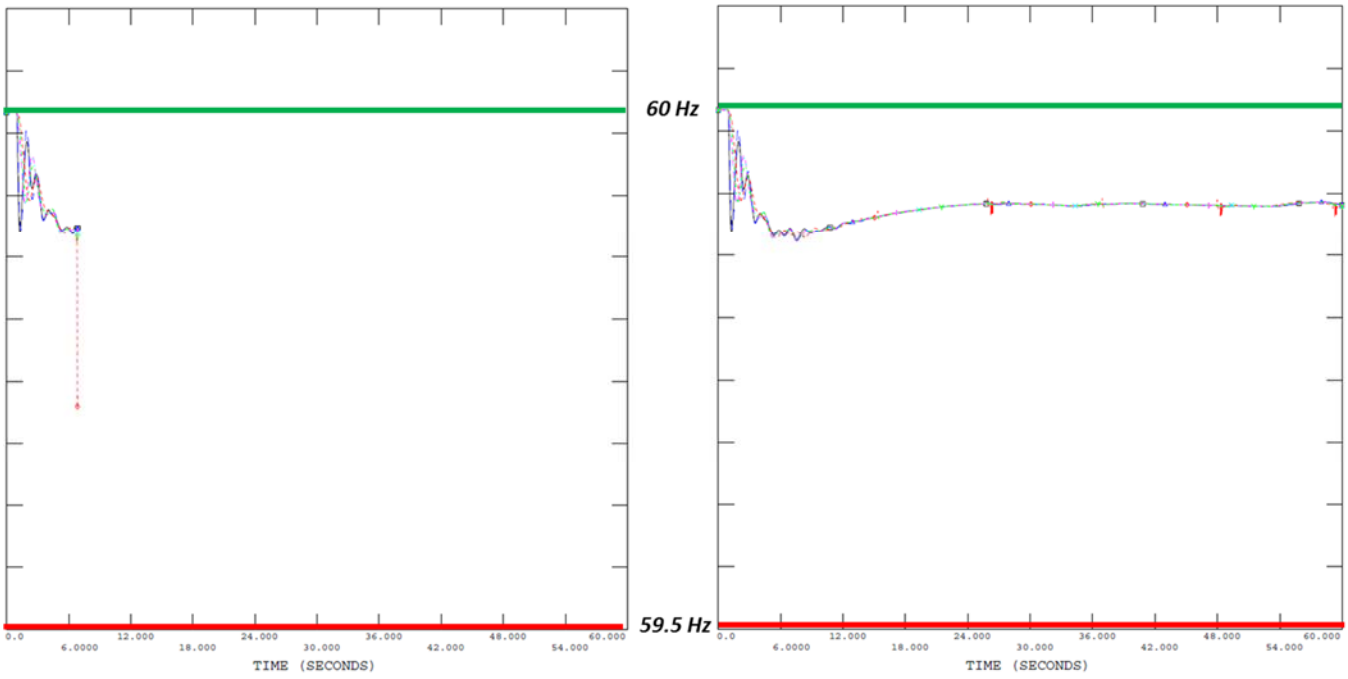


Figure 5: MMWG "Frequency Response Case" Simulations

[19] Multiregional Modeling Working Group

The "frequency response case" simulation for the studied contingency did not accurately reflect frequency response characteristic in the Eastern Interconnection. The frequency responsiveness of the case was significantly degraded by disabling governors across the interconnection (Figure 6). The plot on the left shows the response after disabling governors; this resulted in slightly higher CB_R than actual EI frequency response. Additional online units were squelched to get a lower response more representative of actual EI frequency response and the results of this simulation are shown on the right. This simulation, in conjunction with the vast degradation of FR towards the IFRO shows that the Eastern Interconnection is not likely to reach wide-area first stage UFLS for the studied contingency.

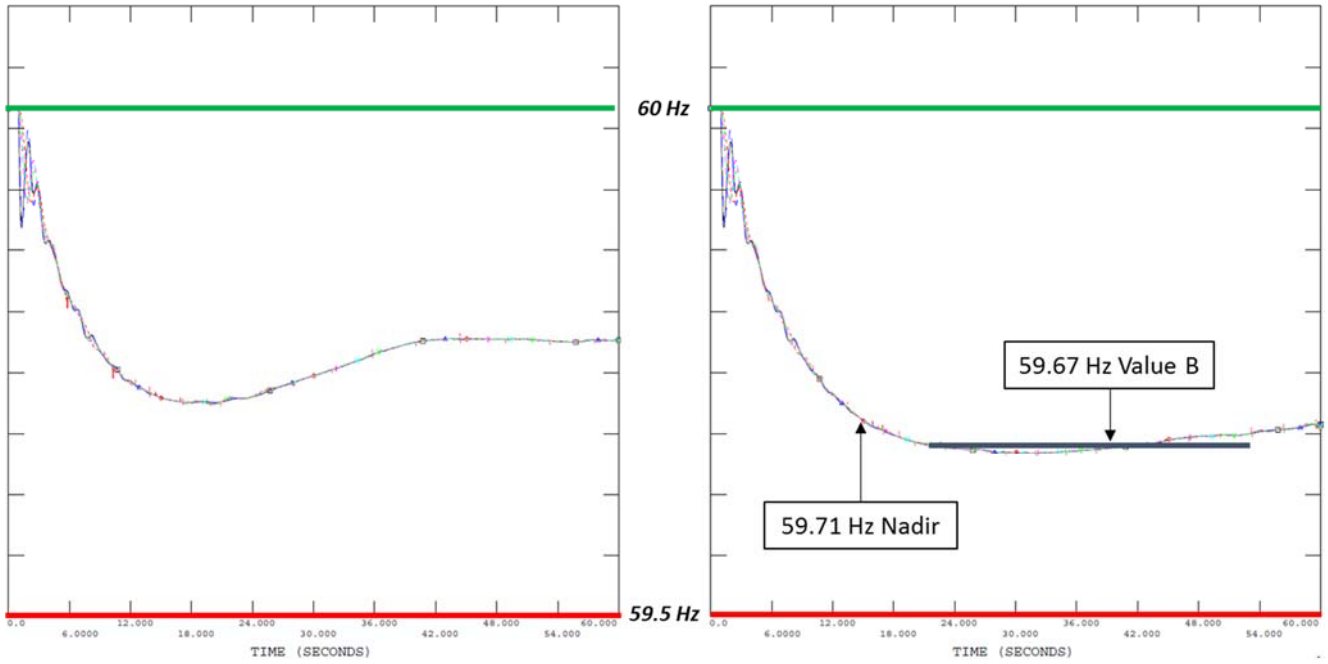


Figure 6: Eastern Interconnection Frequency Response Simulations

Western Interconnection

Dynamic simulation of the defined resource contingency as per BAL-003-1 was performed for the Western Interconnection with frequency response degraded to at least the IFRO value of 841 MW/0.1 Hz. The analysis was performed on a WECC light load near-term planning case with the following modifications:

- The interconnection-wide demand level was reduced from 105 GW to a more representative light load condition of 97 GW.
- Interchanges between areas were held constant while reducing local generation for each area uniformly based on initial demand in the case.

The adjusted WECC case, for the resource loss contingency, gives the response as shown in Figure 7. As the figure shows, frequency response is well above the first stage of UFLS at 59.5 Hz, and with an interconnection frequency response measure (FRM) of 2,119 MW/0.1 Hz. The mean frequency has been used to obtain the representative points shown in the figure.

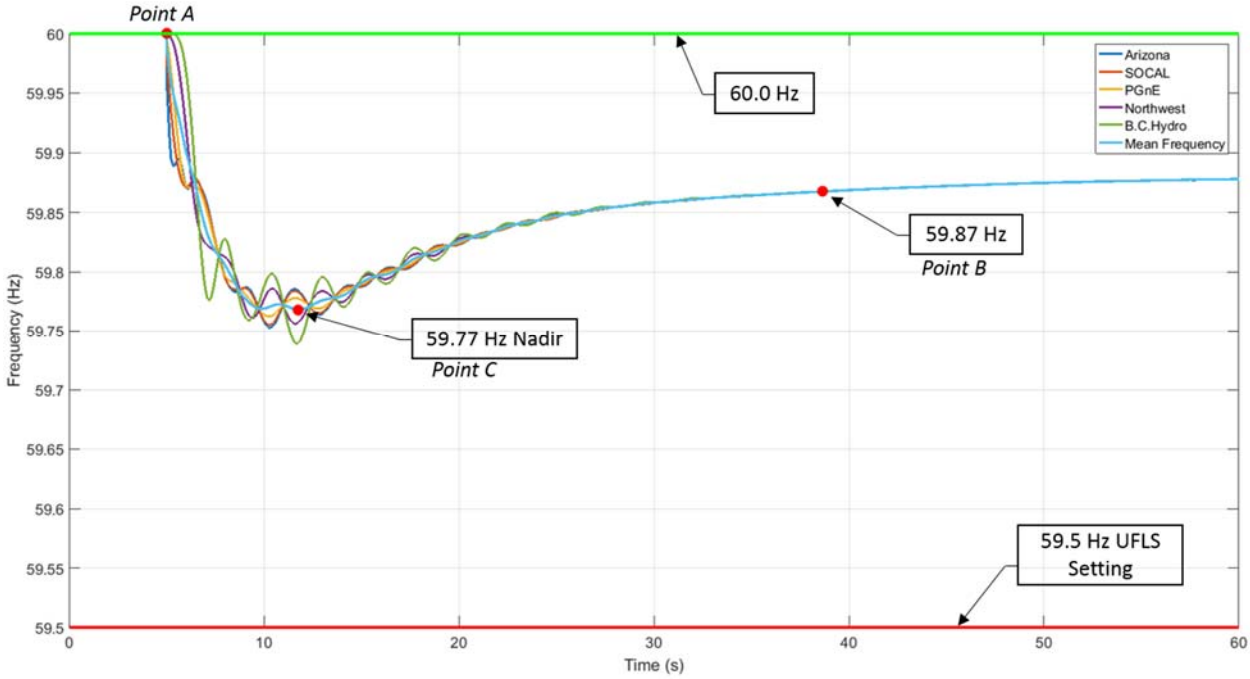


Figure 7: WECC Starting Case Simulation

Frequency response was degraded from this case to a worst case scenario for the West of a response at the IFRO value of around 841 MW/0.1 Hz. This was accomplished by baseloading the majority of generation in certain areas, particularly Southern California and Arizona. Figure 8 shows the response for this case. The CB_R ratio in the simulation is relatively close to the statistically determined CB_R ratio from historical performance.

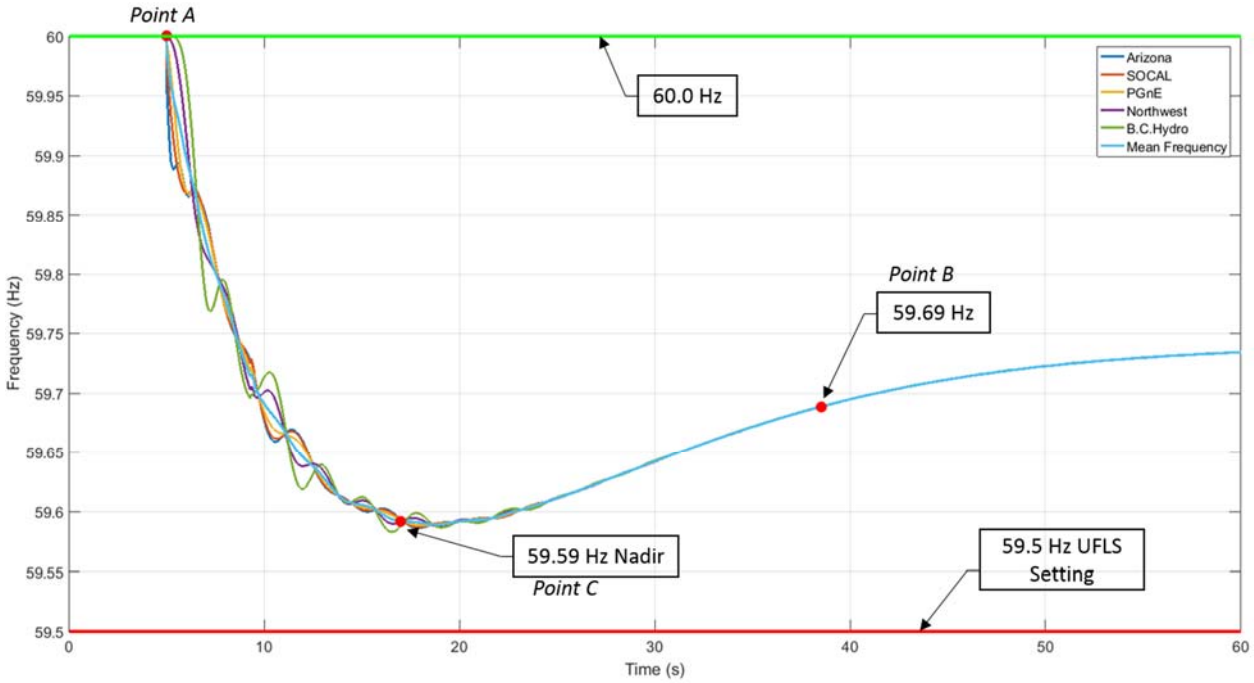


Figure 8: Western Interconnection Frequency Response Simulation

With a frequency response characteristic close to historical performance in the Western Interconnection the frequency nadir, for the defined resource loss protection criteria with response drastically degraded to obtain a FRM equal to the determined IFRO of 841 MW/0.1 Hz, remains above the first stage UFLS at 59.5 Hz.

Texas Interconnection

For Texas Interconnection, the 2018 light load high wind case was used. Figure 9 shows the frequency response of the case as-is. It can be seen that the frequency response is well above the first stage of UFLS at 59.3 Hz, and with an interconnection frequency response measure (FRM) of 1,833 MW/0.1 Hz. This case exhibited abnormal oscillatory behavior likely due to dynamics modeling issues; it is recommended that ERCOT and Texas RE investigate the cause of this simulation response in the post contingency steady state timeframe of the simulation and correct any issues identified.

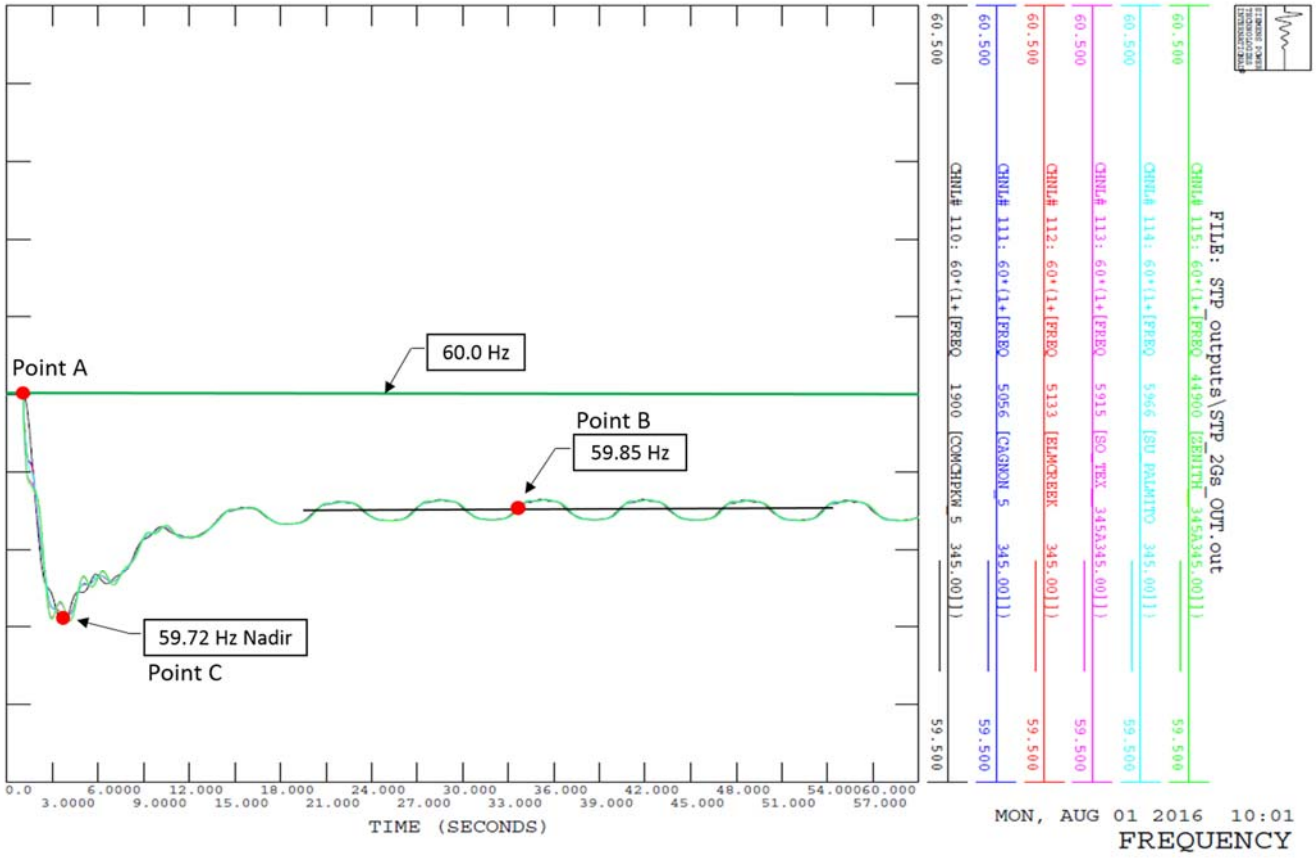


Figure 9: Texas Interconnection Starting Case Simulation

Frequency response was degraded from this case to a worst case scenario for a response at the IFRO value of around 380 MW/0.1 Hz. This was accomplished by switching off many of the governors arbitrarily on units across the interconnection (as for other interconnections' worst case simulations). Figure 10 shows the response for this case. The CB_R ratio in the simulation is relatively close to the statistically determined CB_R ratio from historical performance.

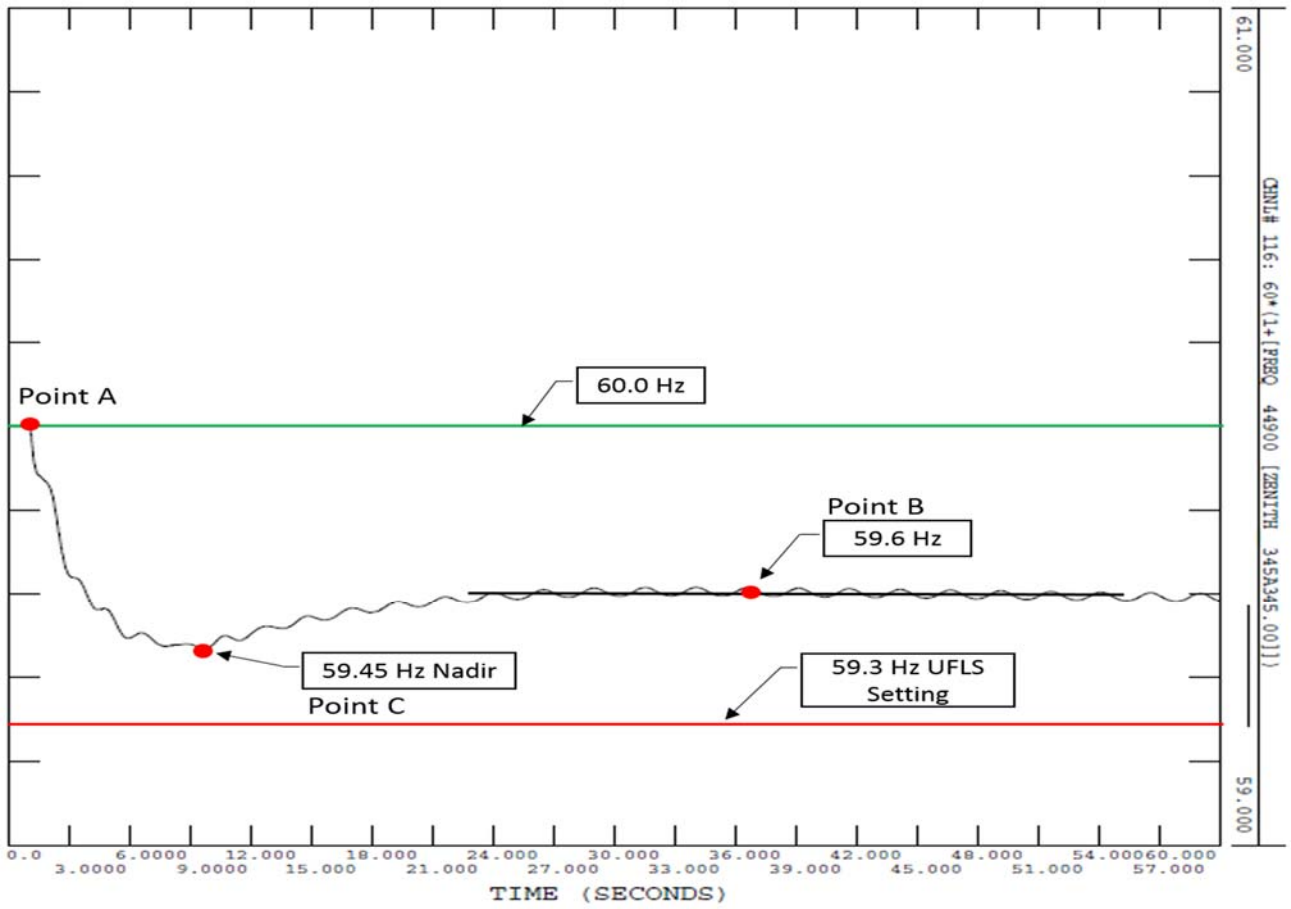


Figure 10: Texas Interconnection Frequency Response Simulation

With a frequency response characteristic close to historical performance in Texas Interconnection, the frequency nadir for the defined resource loss protection criteria with response drastically degraded to obtain a FRM equal to the determined IFRO of around 380 MW/0.1 Hz, remains above the first stage UFLS at 59.3 Hz. It can be seen that the post contingency steady state oscillatory behavior still exists as it did in the root case obtained from ERCOT.

Appendix A: Interconnection Frequency Profiles

Figure A1 shows the probability density function (PDF) for each interconnection for the years analyzed (2012 through 2015). The PDFs for the Eastern, Western, and Quebec Interconnections are consistent with previous years' analysis; however, the Texas Interconnection PDF has changed particularly due to the 2015 distribution.

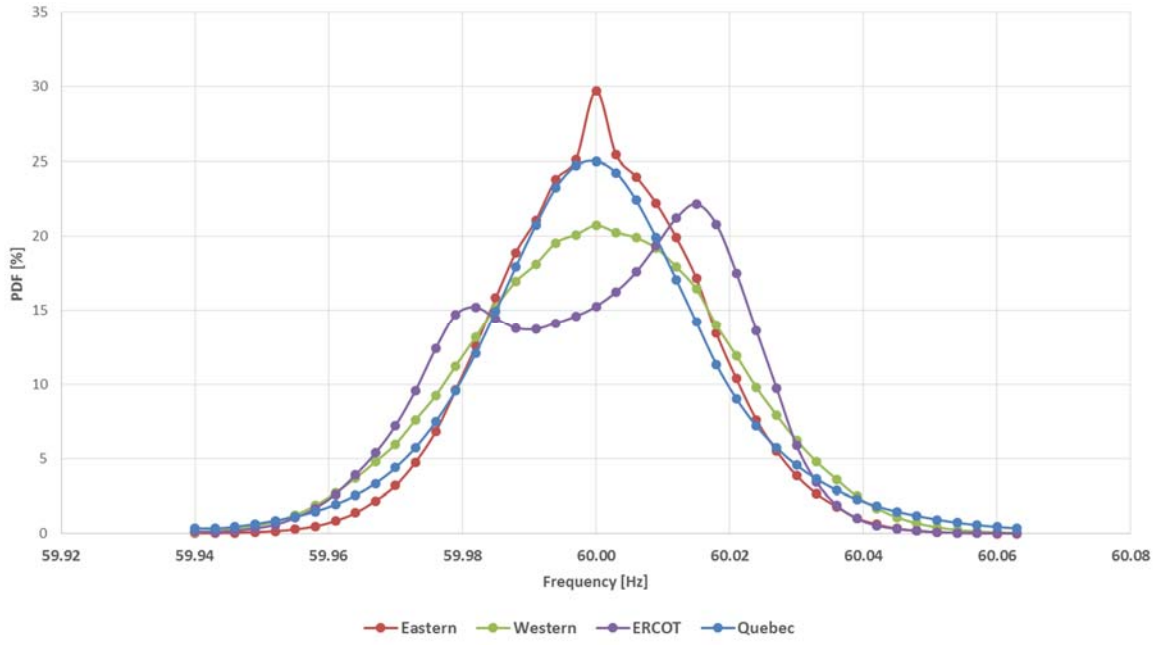


Figure A1: Probability Density Functions by Interconnection 2012-2015 Data

Figure A2 shows the PDF by year (2012 through 2015) for Texas Interconnection. It is clear that the frequency profile in 2015 is significantly different than the profiles for previous years. This can be attributed to implementation of the BAL-001-TRE-1. The right side tail of the PDF has moved closer to nominal 60 Hz, with a predominant peak near 60.017. This is consistent with BAL-001-TRE-1 Requirement R6.1, requiring governor deadbands for steam and hydro turbines with mechanical governors have a deadband setting within +/- 0.034 Hz and all other generating units/generating facilities to have a deadband setting within +/- 0.017 Hz. With the majority of new generation coming online in the ERCOT region being wind and natural gas resources, these facilities will have deadband settings of +/- 0.017 Hz.

It is clear from these observations that the BAL-001-TRE-1 standard has resulted in tighter frequency control. The PDF distinctly shows the impact of wind frequency response and deadband settings moving the right side inward and increasing the amount of time spent inside the 0.017 Hz upper deadband for those resources.

Analysis of frequency response for Texas Interconnection events in 2015 and early 2016 show a general improvement over that for 2013 and 2014. It was postulated that primary frequency response may improve when above the 60.017 Hz deadband due to the curtailed resources. However, examination of frequency events that start at or above the deadband was inconclusive. Since the sample was very small, further review is warranted in next year's FRAA.

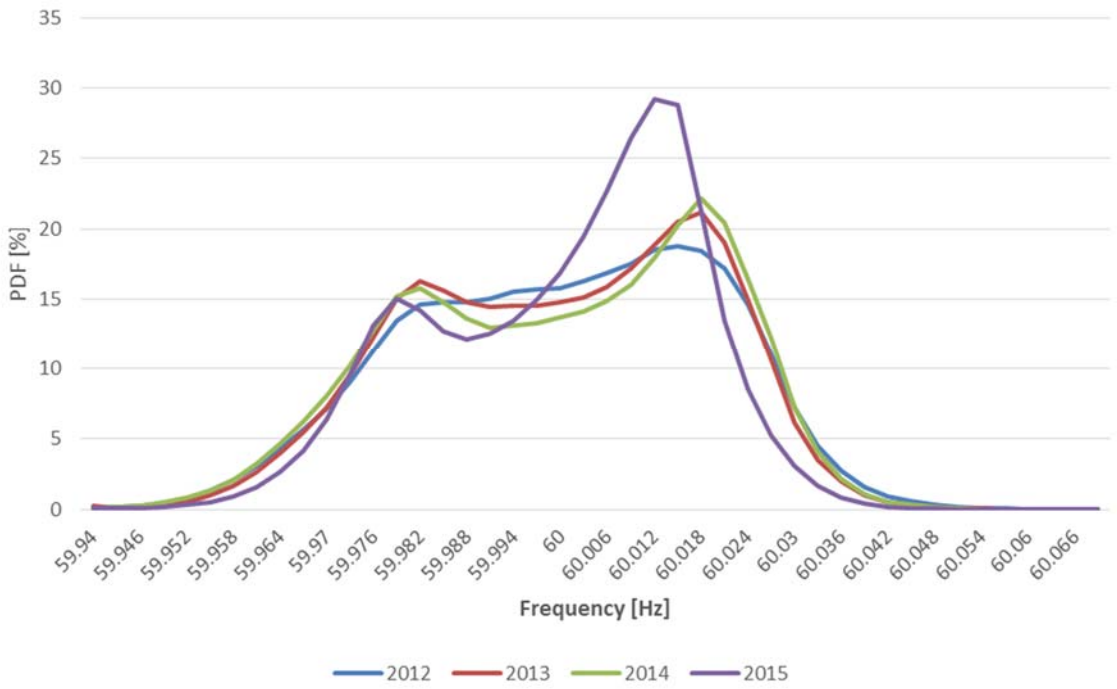


Figure A2: Texas Probability Density Function for Years 2012-2015

The Quebec Interconnection has a consistent year-to-year change in the frequency PDF. The change indicates growing spread of frequency values, which is also confirmed by increasing standard deviation of annual samples. This implies that in the Quebec Interconnection, frequency variability is increasing.

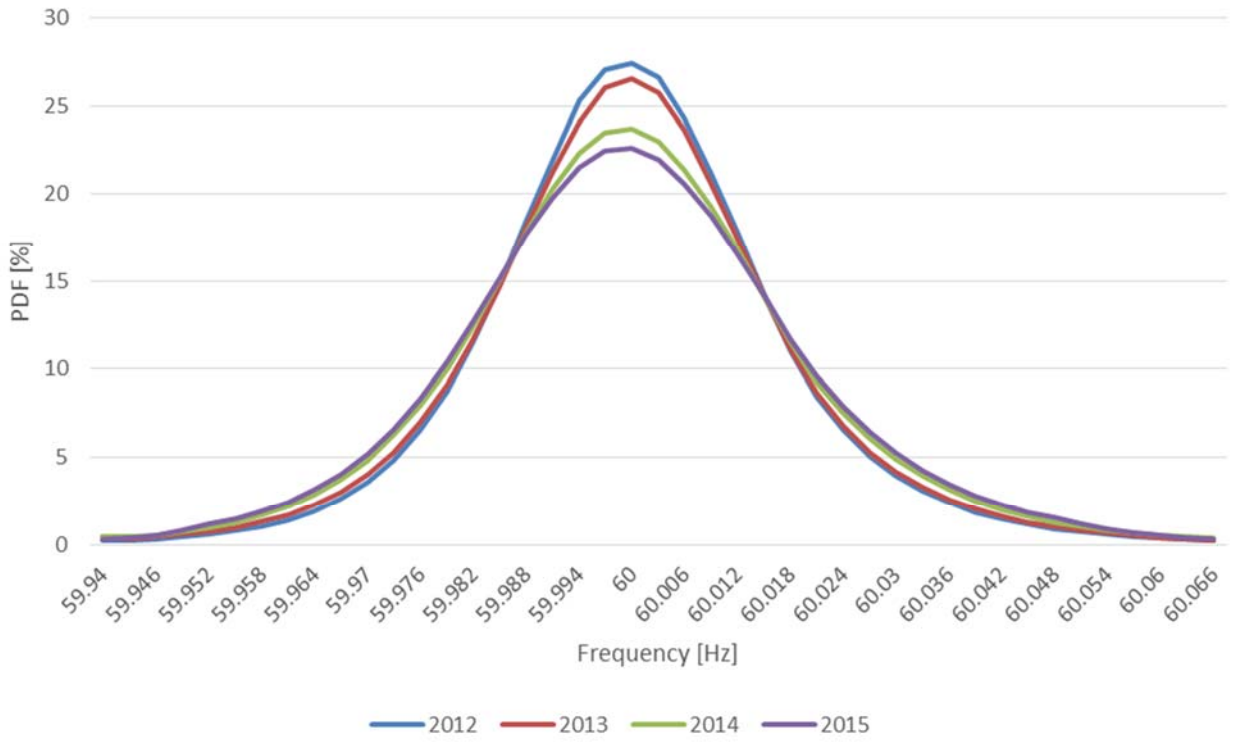


Figure A3: Quebec Probability Density Function for Years 2012-2015

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 14, 2016

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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) June 20, 2013 order[2] and the Commission's September 18, 2014 order[3] requiring an annual report on NERC's FFT program and combines the evaluation of CEs with the annual sampling of FFTs in compliance with the Commission's November 13, 2015 order.[4]

Since 2011, the ERO Enterprise[5] has used the FFT program to resolve over 2,300 instances of noncompliance with the NERC Reliability Standards, 95% of which posed a minimal risk to the reliability of the bulk power system (BPS).[6] 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 to address moderate risk issues

[1] The Commission certified NERC as the ERO in accordance with Section 215 of the FPA on July 20, 2006. *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 (2006), order on reh'g and compliance, 117 FERC ¶ 61,126 (2006), aff'd sub nom. *Alcoa Inc. v. FERC*, 564 F.3d 342 (D.C. Cir. 2009).

[2] *North American Electric Reliability Corp.*, 143 FERC ¶ 61,253 (2013).

[3] *North American Electric Reliability Corp.*, 148 FERC ¶ 61,214 (2014).

[4] *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).

[5] The term "ERO Enterprise" refers to NERC and the eight Regional Entities. The eight Regional Entities are Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst (RF), SERC Reliability Corporation (SERC), Southwest Power Pool Regional Entity (SPP RE), Texas Reliability Entity (Texas RE), and Western Electricity Coordinating Council (WECC).

[6] NERC's searchable public FFT spreadsheets are available on its Enforcement and Mitigation website. *See Enforcement and Mitigation*, NORTH AMERICAN ELECTRIC RELIABILITY CORP., http://www.nerc.com/pa/comp/CE/Pages/Enforcement-and-Mitigation.aspx (last visited Nov. 7, 2016).

will result in a "more efficient enforcement process and allow NERC and the Regional Entities to focus on occurrences of severe risk violations."[7]

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 one thousand instances of noncompliance posing a minimal risk to the BPS through CEs since the inception of that program.

In 2016, NERC and FERC staff completed their annual coordinated review of FFTs and the first annual review of CEs and found the ERO Enterprise appropriately handles noncompliance posing a minimal and moderate risk through these programs.[8] NERC and Commission staff agreed with the final risk determinations for all FFTs and CEs sampled, and noted significant improvement in the clear identification of root cause in all samples posted after the feedback calls from the previous year's survey.[9] Commission staff also agreed with NERC that the FFT and CE programs are meeting expectations.

The FFT and CE programs have been instrumental in streamlining processes and ensuring the efficient processing of noncompliance. Based on what the ERO Enterprise has learned over the last five years, both from the annual reviews as well as from process reviews and analyses of posted and filed noncompliance, NERC and the Regional Entities continue to identify enhancements to the FFT and CE programs. NERC has completed an analysis of CEs beyond

[7] *North American Electric Reliability Corp.*, 148 FERC ¶ 61,214 at P 1.

[8] *See North American Electric Reliability Corp.*, 143 FERC ¶ 61,253 (2013); *see also North American Electric Reliability Corp.*, 148 FERC ¶ 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.*, Notice of Staff Review of Compliance Programs, Docket No. RC11-6-004 (FERC June 15, 2016).

[9] *See infra* Appendix B.

those reviewed with FERC, and is currently reviewing repeat noncompliance, moderate risk noncompliance, and the Regional Entity implementation of the Self-Logging Program. Although complete analysis of each of these subjects is not finalized, initial conclusions are referred to below as appropriate.

As several of these reviews are ongoing, NERC is not at this time proposing substantive improvements to the FFT or CE programs for FERC approval, although it is requesting approval of a minor adjustment to the time for completion of mitigation activities to align the FFT and CE programs, as further described below. Nevertheless, NERC has identified potential areas of improvement to be proposed in the near future. Among other things, the ERO Enterprise is considering the means of reporting on minimal risk noncompliance and avenues of expansion for the CE program. NERC anticipates proposing certain program improvements in its 2016 Annual Compliance Monitoring and Enforcement Program Report filing in February 2017.

II. THE FFT AND CE PROGRAMS HAVE BEEN SUCCESSFULLY IMPLEMENTED AND HAVE CONTINUED TO EVOLVE SINCE INCEPTION

The FFT and CE programs, with the Self-Logging Program, are major elements of the ERO Enterprise's risk-based approach to enforcement.[10] The FFT program resolves noncompliance posing a minimal or moderate risk to the reliability of the BPS, while the CE program resolves minimal risk noncompliance 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

[10] For a description of the alternative enforcement processes, enforcement discretion, CEs, and FFTs, *see* NERC Rules of Procedure, app. 4C §§ 3.8, 3A.0, 3A.1, & 5.2A, respectively.

Applicable Governmental Authorities; (c) tracking and analysis of the noncompliance as necessary to identify risks; and (d) the opportunity for the registered entity to opt-out.[11] These programs have streamlined processing, reduced caseload in process, 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 enforcement of Reliability Standards that recognizes not all instances of noncompliance require the same type of process and documentation. Over the last five years, the FFT program evolved from a processing track limited to minimal risk noncompliance to a vehicle for 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. The ERO Enterprise now uses these programs to resolve more than half of discovered noncompliance.[12]

Use of the FFT program has contributed to the significant reduction of the ERO Enterprise caseload to be processed. For example, in 2014, the ERO Enterprise reduced the older caseload from 483 pre-2013 instances of noncompliance to just 35.[13] In other words, the ERO Enterprise was able to process those older instances of noncompliance while continuing to process newer violations. The reduction in the active caseload discovered prior to 2013 reduced the average age

[11] *See* NERC Rules of Procedure, app. 4C §§ 5.2A, 3A.

[12] *See* North American Electric Reliability Corp., *Compliance Monitoring and Enforcement Program Report: Third Quarter 2016* (Nov. 1, 2016), http://www.nerc.com/gov/bot/BOTCC/Compliance%20Committee%20201/Compliance%20Committee%20Open%20Meeting%20-%20November%201%202016.pdf.

[13] *See* North American Electric Reliability Corp., *Key Compliance Metrics and Trends: Fourth Quarter 2014*, at 3 & fig.2 (Feb. 11, 2015). All NERC Enforcement analysis and violation statistics are available on NERC's website. *See Enforcement Analysis and Violation Statistics*, NORTH AMERICAN ELECTRIC RELIABILITY CORP., http://www.nerc.com/pa/comp/CE/Pages/Compliance-Violation-Statistics.aspx (last visited Nov. 14, 2016).

of noncompliance in the ERO Enterprise inventory to 9.9 months by the end of 2014.[14] Since 2012, 45% of dispositions have been FFTs and CEs (30% and 15% respectively), significantly contributing to the ERO Enterprise's ability to manage and prioritize processing of the caseload based on risk. Because of successive improvements to the FFT program, in particular the extension to moderate risk noncompliance in 2013, NERC and the Regional Entities are able to handle minimal and moderate risk noncompliance efficiently and effectively and focus their resources on noncompliance posing a greater risk to the reliability of the BPS.[15] Registered entities and Regional Entities have experienced efficiency gains due to the reduced documentation and negotiation required for FFTs.[16] Similarly, the CE program remains a key element in implementing the risk-based approach to enforcement of NERC Reliability Standards. For example, in 2015, the ERO Enterprise used CEs to resolve nearly half of the minimal risk noncompliance. In 2016, CEs now exceed all other enforcement methods for processing minimal risk noncompliance.[17]

The FFT and CE programs have helped the Regional Entities reduce the average age of the noncompliance in their inventories. As of Q3 2016, 68% of the noncompliance inventory is now less than one year old and only 9% is over two years old. FRCC, NPCC, RF, and Texas RE have completed processing of all noncompliance with discovery dates prior to 2014.[18] At the same

[14] *See* North American Electric Reliability Corp., *Key Compliance Metrics and Trends: Fourth Quarter 2014*, at 3.

[15] *See North American Electric Reliability Corp.*, 148 FERC ¶ 61,214 at P 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).

[16] *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 (Mar. 15, 2013).

[17] *See* North American Electric Reliability Corp., *Compliance Monitoring and Enforcement Program Report: Third Quarter 2016*, app. A, at 13 fig.7.

[18] *Id.*

time, there are only 191 pre-2014 instances of noncompliance remaining to be processed across MRO, SERC, SPP RE, and WECC, and most of these instances of noncompliance are from federal entities.[19]

The ERO Enterprise's use of the FFT and CE programs has continued to increase since FERC initially approved them. FFTs were used to resolve approximately 3% of moderate risk noncompliance in 2014 and almost 22% of moderate risk noncompliance in 2016. Using FFT to resolve moderate risk noncompliance has meant violations posing a more significant risk have received increased attention and resources through processing in spreadsheet Notices of Penalty (NOPs) or full NOPs.

In 2013, approximately 43% of all processed noncompliance were treated as FFTs.[20] FFTs accounted for approximately 34% and CEs almost 10% of noncompliance in 2014.[21] In 2015, the percentages essentially reversed, with CEs making up over half of all processed noncompliance and FFTs representing approximately 8%.[22] As of November 1, 2016, CEs continue to make up around half of all processed noncompliance.[23] This is consistent with the fact, regularly observed, that a large portion of the noncompliance with Reliability Standards poses a minimal risk to the

[19] The ERO Enterprise kept noncompliance related to federal entities on "hold" pending a decision in *Southwestern Power Admin. v. Federal Energy Regulatory Comm'n*, 763 F.3d 27 (2014) (*Southwestern Power*). On August 22, 2014, the District of Columbia Circuit resolved *Southwestern Power*, ruling that FERC, and by extension NERC and the Regional Entities it oversees, could not impose monetary penalties against federal government entities. *See id.* at 29-30, 36.

[20] *See* North American Electric Reliability Corp., *Key Compliance Metrics and Trends: Fourth Quarter 2013*, at 10.

[21] *See* North American Electric Reliability Corp., *Key Compliance Metrics and Trends: Fourth Quarter 2014*, at 22.

[22] *See* North American Electric Reliability Corp., *2015 ERO Enterprise Compliance Monitoring and Enforcement Program Annual Report*, at 14.

[23] As of November 1, 2016, NERC has posted 380 CEs out of 744 total posted or filed instances of noncompliance. *See supra* n.6.

reliability of the BPS.[24] The Regional Entities' effective use of CEs and FFTs, demonstrated through oversight mechanisms such as the annual review described below shows increased consistency in processing and understanding of the risk associated with individual noncompliance across the ERO Enterprise.

III. JOINT NERC AND FERC ANNUAL REVIEW OF THE FFT AND CE PROGRAMS

As part of oversight of the FFT and CE programs, NERC and FERC staff conducted the 2015 annual review of FFTs and CEs. 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 CEs and FFTs; (c) assessed successful mitigation completion for FFTs and CEs with ongoing mitigating activities; (d) identified region-specific best practices and areas for improvement; and (e) provided observations to the Regional Entities related to the timeliness and completeness of the programs. Through this review, FERC staff and NERC staff determined whether the Regional Entities were following the NERC CMEP and successfully implementing the FFT and CE programs.[25]

On June 15, 2016, FERC issued its Notice of Staff Review of Compliance Programs.[26] Notably, FERC staff agreed with the final risk determinations for all samples and noted significant improvement in the clear identification of root cause in all samples posted after the feedback calls from the previous year's survey.[27] On June 20, 2016, NERC staff filed a statement that included

[24] As of November 1, 2016, 80% of total noncompliance the ERO Enterprise has processed has posed a minimal risk to the reliability of the BPS. *Id.*

[25] For a more detailed description of the review, *see infra* Appendices A-B.

[26] Notice of Staff Review of Compliance Programs, Docket No. RC11-6-004 (FERC June 15, 2016).

[27] *See infra* Appendix B.

similar findings. FERC staff also agreed with NERC that the FFT and CE programs are meeting expectations. In June 2016, NERC staff provided individual feedback to the Regional Entities with specific findings and recommendations for each region.

Sampling for the 2015 program year[28] indicated that the Regional Entities appropriately included the sampled noncompliance in the FFT and CE programs and that the registered entities adequately mitigated all 132 instances of noncompliance, including 11 self-logged CEs (approximately 10% of the CEs reviewed). The sample analysis did indicate a small number of documentation issues, particularly with regard to the quality of the information contained in the FFT and/or CE postings.[29] For example, a few of the FFTs or CEs lacked some of the information necessary for posting, such as start or end dates and factors affecting the risk during the pendency of the noncompliance. Subsequent review of the supporting information for these FFTs or CEs, however, identified a majority of the missing information.[30]

The results of the 2015 annual review show a consistent improvement in program implementation. They indicate, among other things, that most registered entities, in coordination with their respective Regional Entity, are able to identify, mitigate, and remediate minimal, as well as certain moderate, risk noncompliance. They also show significant alignment across the ERO Enterprise. Including the processing and understanding of the risk associated with individual noncompliance. For a more detailed discussion of the findings from the annual FFT and CE review, see Appendices A and B.

[28] For FFTs, the program year was October 1, 2014 through September 30, 2015. For CEs, the review period was May 1, 2014 through September 30, 2015.

[29] *See infra* Appendix B.

[30] *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. 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. NERC has also completed an analysis of 630 CEs, and is performing analysis of: (a) the Regional Entities implementation of the Self-Logging Program; (b) repeat noncompliance; and (c) moderate risk noncompliance.

A. CE Analysis

In 2016, NERC staff completed an analysis of 630 CEs posted in 2014 and 2015. Fifteen percent of the CEs analyzed were self-logged noncompliance.[32] NERC regularly evaluates noncompliance to look for trends or other relevant information to disseminate to Regional Entities or registered entities as appropriate. Generally, NERC found that, in most of the cases reviewed, registered entities had internal controls and defenses in place at the time of issue that prevented the noncompliance from escalating to moderate or serious risk noncompliance. Through the review, NERC was able to identify four recurring themes with the CEs, even though the instances involved a diverse array of underlying conduct, facts, and circumstances.

[31] *North American Electric Reliability Corp.*, 150 FERC ¶ 61,108 at P 47-48 (2015) (Risk-Based CMEP Order).

[32] The Self-Logging Program provides the Regional Entities the opportunity to perform formal reviews of entity's internal controls, which provides reasonable assurance of the entity's ability regarding identifying, addressing, and preventing noncompliance and future risk to the BPS. This allows registered entities and Regional Entities to focus their effort on matters that have a greater impact on reliability while continuing to find more minimal risk issues and correct them in an expeditious manner. This reasonable assurance supports the presumption of CE treatment for self-logged items.

First, the review of the CEs identified noncompliance consisting of minor mistakes and missteps when implementing programs, such as conflicting program requirements or inadequate communication between departments, as opposed to a more widespread failure or lack of mature programs. The instances of noncompliance were not due to major organizational or programmatic deficiencies.

Second, many of the registered entities discovered the noncompliance because of strong internal review processes that employed layers of review and internal audits. These instances of noncompliance were not due to fundamental failures in internal controls.

Third, the majority of noncompliance related to previous mitigation was merely of a "record keeping" nature, not due to a failure in previously implemented mitigation. Over 15,000 instances of noncompliance have been reported in the United States since the NERC Reliability Standards became mandatory and enforceable in 2007. Therefore, some level of repetition in noncompliance is not surprising. For this reason, the risk assessment of CEs also includes information about past noncompliance and how the Regional Entity factors that history in its determination of CE treatment. For repeat noncompliance, in most instances, the CE did not include the same relevant conduct as past noncompliance, supporting its treatment as a CE.

Finally, while many of the reviewed CEs included updates to internal processes combined with internal training in their mitigating activities, the majority of these CEs did not have deficient past training or lack of internal processes or procedures listed as the root cause of the noncompliance. Instead, the nature of the procedural changes and training was aimed at providing clarity and raising overall awareness within relevant departments at the registered entity.

B. Self-Logging Program Process Review

On November 3, 2014, NERC, in conjunction with the Regional Entities, submitted a filing describing enhancements to the risk-based CMEP in which NERC discussed two primary components of risk-based enforcement–CEs and the Self-Logging Program. NERC proposed that registered entities with demonstrated effective management practices to self-identify, assess, and mitigate minimal risk instances of noncompliance would: (a) record issues on a non-public log in lieu of individual Self-Reports; (b) have their Regional Entities periodically review and approve the log; and (c) receive CE treatment once its Regional Entity approved the logged issue.

FERC's order, issued February 19, 2015, approved NERCs implementation of the additional components, including CEs and self-logs, but instructed NERC to post the CEs publicly similar to its FFT posting.[33] FERC's intent in directing that CEs, including those originating from self-logs, be made public was "to educate industry to avoid and mitigate noncompliance with reliability standards, and to maintain the credibility of NERC's compliance and enforcement regime."[34] The proposed Self-Logging Program was new to the ERO Enterprise, so additional oversight at the time was appropriate. The Self-Logging Program has continued to mature since the February 2015 Order, with 62 registered entities in the Self-Logging Program and self-logged instances of noncompliance making up approximately 14% of CEs as of Q3 2016.[35]

[33] *North American Electric Reliability Corp.*, 150 FERC ¶ 61,108 at P 26, 36.

[34] *See id.* at P 36.

[35] *See* North American Electric Reliability Corp., *Compliance Monitoring and Enforcement Program Report: Third Quarter 2016*, app. A, at 11-12 fig.4 (Nov. 1, 2016); *see also* North American Electric Reliability Corp., *Compliance Monitoring and Enforcement Program Report: Second Quarter 2016*, app. A, at 14 fig.5 (Aug. 10, 2016).

As mentioned previously, approximately 10% of the CEs reviewed in the 2015 joint FFT/CE review and 15% of the CEs reviewed in the 2016 CE analysis were self-logged. NERC staff is also currently performing a process review of the Regional Entities' self-logging procedures. This review is to assess compliance with the CMEP, relevant FERC Orders, and the ERO Self-Logging Program,[36] to evaluate the consistency of each Regional Entity's practices, and to identify potential areas for improvement.

To perform the review of this program, NERC requested each Regional Entity provide documents on its outreach, formal evaluations of the registered entities' internal controls, and decision-making processes when deciding whether to approve a registered entity for self-logging. NERC staff is assessing the accessibility of the program to registered entities and making recommendations for improvement. NERC's review focuses on six high level aspects of the Self-Logging Program: (a) procedural consistency; (b) eligibility determinations; (c) level and means of outreach; (d) how the Regional Entities use the program beyond the minimum requirements of reporting noncompliance; (e) potential areas of expansion for the program; and (f) accuracy of self-logged issues.

NERC has provided this list of high-level topics to FERC staff. FERC staff will also receive a copy of the final analysis of the process review. NERC's initial review of the Regional Entities' Self-Logging programs is essentially complete and suggests that Regional Entities have appropriately admitted program participants based on the identification of effective management

[36] ERO Enterprise Self-Logging Program (February 1, 2016), http://www.nerc.com/pa/comp/Reliability%20Assurance%20Initiative/Updated_ERO%20Enterprise%20Self-Logging%20Program%20(2-1-16).pdf.

practices to self-identify, assess, and mitigate minimal risk instances of noncompliance. NERC staff anticipates its analysis to be complete in mid-December 2016.

C. Other Analysis of Noncompliance

On November 20, 2014, the Commission issued its Five-Year Order[37] in which it directed NERC to include in its next five-year assessment an analysis of repetitive noncompliance.[38] Specifically, FERC requested more clarity regarding the effect the ERO Enterprise's compliance monitoring and enforcement program is having on reducing repeat noncompliance. The Commission identified repeat noncompliance as a "key indicator" of the effectiveness of the CMEP on recognizing, mitigating, and preventing violations.[39] NERC has reviewed over 7,400 instances of noncompliance from July 2011 through the end of September 2016. NERC is focusing its analysis on correlations amongst the repeat noncompliance, the increase or decrease in risk of repeat noncompliance, and the principal reasons behind recurrence—in particular, whether the issues stem from conduct similar to that underlying a prior violation of the same or a closely related Reliability Standard requirement.

NERC also has plans to conduct a comprehensive analysis of moderate risk noncompliance. Notably, NERC has only filed 14 moderate risk zero-dollar penalty violations outside of the FFT program since the start of 2015.[40] As of Q3 2016, NERC has processed 29

[37] *North American Electric Reliability Corporation*, 149 FERC ¶ 61,141 (2014) (Five-Year Order).

[38] *Id.* at P 39 ("[W]e direct NERC to include an analysis of repeat violations in its next Performance Assessment that will allow NERC, the Regional Entities, and the Commission to evaluate whether NERC's compliance and enforcement efforts have been effective in improving registered entities' compliance and overall reliability.").

[39] *Id.*

[40] This number does not include "no penalty" federal entity violations, which, because of their age and procedural history, have been primarily processed using the full or spreadsheet NOP track. Of the 14 moderate risk violations processed outside of the FFTs program, NERC processed ten as a part of larger disposition packages. The Regional Entities did not extend FFT treatment to 2 of the 14 because they were either identified through Compliance Audit

FFTs in 2016—only four included a minimal risk noncompliance.[41] The 25 moderate risk issues were primarily self-identified; the involved registered entities had robust compliance programs and mitigated the noncompliance quickly. Among other things, the analysis will provide more detail regarding the types of treatment appropriate for noncompliance posing a moderate risk to reliability.

Through the various processes and analyses described here, NERC and the Regional Entities continue to identify potential improvements for all enforcement-related processes. Based on the results of its review of CEs, repeat noncompliance, moderate risk noncompliance, and the results of reviews of the Self-Logging Program NERC is conducting now, NERC expects to identify and propose potential program improvements in its 2016 Annual Compliance Monitoring and Enforcement Program Report filing.

V. PROPOSED PROGRAM IMPROVEMENT

In its September 2014 Order, FERC noted the accepted time frame for completing mitigation activities for registered entities is one year after FFT posting. In its November 4, 2015 Order, FERC accepted that registered entities are required to mitigate noncompliance resolved through a CE within 12 months *of the time of the notification to the registered entity of CE treatment*.[42] NERC proposes to modify this timeframe to be within 12 months *of the time of the posting of the CE*. This minor adjustment would align the mitigation completion activity

or self-reported prior to a Compliance Audit. One remaining violation was processed as a spreadsheet NOP because of negative compliance history and the other was a roll-in violation containing three separate instances.

[41] One of these minimal risk FFTs was negotiated prior to FERC's approval of the CE program. At the time the Regional Entity submitted the issue to NERC, NERC identified the need for additional scrutiny and then, due to an administrative error, did not post the FFT until 2016. The remaining three FFTs were instances of minimal risk noncompliance for a single entity processed together.

[42] *North American Electric Reliability Corporation*, 153 FERC ¶ 61,130 at P 37 (2015).

timeframe between FFTs and CEs, thus facilitating tracking of completion deadlines. The ERO Enterprise does not anticipate any changes to processing timeframes because of this adjustment.

VI. CONCLUSION

NERC respectfully requests that the Commission accept this report in compliance with the June 20 Order, September 18 Order, and November 13 Order, and approve the minor procedural adjustment requested herein.

Respectfully submitted,

/s/ Leigh Faugust

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Dated: November 14, 2016

APPENDIX A. Methodology and Criteria Applied in FFT and CE Sampling

NERC and FERC staff's 2016 review involved a sample of 32 FFTs for the period of October 2014 through September 2015 and 100 CEs, including 11 self-logged instances, for the period of May 2014 through September 2015. Coordination between NERC and FERC staff made the review more efficient. FERC staff performed the sampling of FFTs and CEs, with feedback from NERC on specific instances to be included in the sample. NERC staff issued data requests to the Regional Entities on behalf of both organizations.

FERC staff used RATS-STATS[43] to select 18 CIP and 14 non-CIP FFTs from 161 FFTs posted in fiscal year 2015. FERC staff also selected 54 CIP and 46 non-CIP CEs from 499 CEs posted from May 1, 2014 through September 30, 2015.

Table 1: Sample Size of FFTs for all Regional Entities

	Total Processed	Selected	Percent representation of total processed	Percent representation of selected
Total	161	32	% of 161	% of 32
FRCC	10	2	20%	6%
MRO	8	2	25%	6%
NPCC	13	3	23%	9%
RF	14	3	21%	9%
SERC	26	5	19%	16%
SPP RE	20	4	20%	13%
TRE	23	5	22%	16%
WECC	47	8	17%	25%

[43] 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

	Total Processed	Selected	Percent representation of total processed	Percent representation of selected
Total	445	100	% of 445	% of 100
FRCC	14	3	21%	3%
MRO	43	15	35%	15%
NPCC	35	9	26%	9%
RF	142	30	21%	30%
SERC	45	10	22%	10%
SPP RE	50	9	18%	9%
TRE	41	7	17%	7%
WECC	75	17	23%	17%

NERC requested 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; 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 program Review Checklist.[44] The criteria were based on three major categories: (a) the description of the issue was clear and sufficient facts were included; (b) the risk was aligned with the facts and circumstances of each particular issue; and (c) the issues were mitigated timely and appropriately, with open issues being mitigated within one year.

In addition to the above criteria, NERC 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 in review of the mitigating activities. NERC staff also assessed whether the root cause was appropriately identified, leading

[44] NERC's FFT/CE Process Review Checklist is included as **Attachment 1**.

to effective mitigation. NERC staff's review also focused, as feasible, 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 processed with FERC the information regarding the Regional Entities' processes and the specific FFTs and CEs on a privileged/non-public basis. NERC also took this opportunity to reinforce to the Regional Entities that communications issued after FERC's November 2015 Order should indicate that registered entities retain relevant records for 18 months after the date of posting.

APPENDIX B. Specific Analysis of the Sampled Issues

A. Process documents

NERC found that, in general, each of the Regional Entities' internal documents and procedures regarding the FFT and CE programs follows the NERC Rules of Procedure and CMEP. Each region has detailed internal procedures that provide systematic guidance in the processing of noncompliance. These documents gave NERC the assurance that the regions were determining properly the appropriate processing route for received noncompliance.

B. Description of the issue and risk assessment

NERC and FERC staff reviewed the description of the issue as it pertained to each of the FFTs and CEs sampled. While on occasion, the Regional Entities omitted from the issue description and risk assessments relevant facts and circumstances, those facts and circumstances were not always critical for risk assessment. Nevertheless, those facts may have facilitated better understanding by NERC and FERC staff of the issue or risk to the reliability of the BPS. In addition, there were examples where the Regional Entities either omitted or did not clearly identify the duration of the noncompliance. NERC has updated the FFT and CE spreadsheet template to include duration dates explicitly.

Notably, the Regional Entities made significant improvement in issues posted after last year's feedback calls, identifying the root cause in all FFTs and CEs posted after those discussions. Through review of the provided documents, NERC found that the Regional Entities consistently and accurately addressed the risk presented by the noncompliance through provision of mitigating factors and compensating measures in place for the duration of the issue. For the most part, the Regional Entities supported their risk determinations with facts that existed at the time of the

noncompliance. The Regional Entities provided after-the-fact determinations only in conjunction with facts known at the time of the issue to reinforce the risk determinations. 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.

C. Evaluation and documentation of mitigation activities

As part of the sampling, NERC determined that the Regional Entities were requiring timely mitigation of the FFTs and CEs to address both the instant noncompliance and abatement of future occurrences. Most of the sampled mitigation activities explicitly included measures designed to prevent recurrence of noncompliance.

There were some instances where the posted information left out information that was available in the underlying documentation—the posting was still accurate, however additional information could have been included. For example, there were identified issues where a direct link between the root cause and the mitigation activities to address that root cause was not clear; however, NERC did not identify any issues where the mitigation activity was not adequate to address and remediate the noncompliance. For ongoing noncompliance, i.e. issues with mitigation activities still outstanding at the time of posting, there were examples of failure to include a description of the compensating measures in place during the pendency that would reduce risk until mitigation was complete. NERC has updated its templates to require more clearly that this information be included.

While this group of sampled issues notably improved from the prior year's review, there was one example where the Regional Entity expanded the scope of the FFT after the posting. This expansion occurred during the registered entity's mitigation of the issue. Although the risk

remained minimal after the expansion, in a different case it could have elevated. This was the only example in the sampled group of an expansion of scope after posting. FERC staff and NERC provided direct feedback that Regional Entities need to convey to NERC and FERC any future changes to issues posted accordingly.

NERC continues to identify Regional Entities still requiring formal Mitigation Plans instead of mitigation activities. NERC also identified Regional Entities that continue to verify mitigation completion for all noncompliance regardless of disposition method, instead of on a sampling basis for streamlined processing methods. NERC continues to work with the Regional Entities to update their verification processes. Accepting mitigation activities for lesser risk issues that qualify for streamlined processing and sampling verification for minimal risk issues—especially for those entities in the Self-Logging Program that have provided evidence of internal processes related to finding, fixing, and preventing noncompliance—should further increase processing efficiencies.

ATTACHMENT 1. Process Review Checklist

2015 – 2016 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 document - explain that the document is about*
Title, revision	*Summary of document - explain that the document is about*
Title, revision	*Summary of document - explain that the document is about*
Title, revision	*Summary of document - explain that the document is about*

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 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 document - explain that the document is about*
Title, revision	*Summary of document - explain that the document is about*
Title, revision	*Summary of document - explain that the document is about*
Title, revision	*Summary of document - explain that the document is about*

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?” 2) 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? The risk was not considered a minimal risk simply because of no adverse impact ("no harm no foul"). Was the risk determined in a consistent manner? For minimal risk issues, was CE/FFT treatment appropriate?1) NERC Enforcement will assess, as feasible, whether internal controls contributed to the mitigation of the risk during the pendency of the noncompliance;

3. Were the issues mitigated successfully? For ongoing mitigation, was it successfully completed and certified? 3) If the CE/FFT is associated with a formal Mitigation Plans, NERC Enforcement will ask the Regional Entity to explain the circumstances that

4. NERC Enforcement will communicate to the REs that communications issued after the FERC order dated [November 2015] request that the registered entities retain relevant records for 18 months after date of posting of CEs.

	Questions	Issue Tracking ID
	Type - FFT/CE	
	Standard	
	Requirement	
	Documents Received: List specific documents received for this violation ID here	
1	The description of the issue was adequate and includes the following: a) Description of the issue, underlying facts and circumstances. For CEs, indicated if it was self-logged (applicable to CEs posted since May 2015). b) Discovery date and method of the issue. c) 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 facts at the time of the issue, not just after-the-fact determinations. c) Risk statement addresses mitigating factors that reduced the risk and compensating factors at the time of the issue which reduced the potential risk as relevant to the entity and circumstances. (Does not include a blanket heightened risk statement related solely to the Standard (R) at issue.) d) 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) e) Compared to the evidence, the posted description of the risk assessment is accurate and reasonably complete. f) Compensating measures or internal controls are in place during the period of noncompliance which reduce the risk to reliability while mitigation is ongoing. Are internal controls contributing to the mitigation of the risk of noncompliance?	

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 - is root cause identification contributing to more efficient mitigation of noncompliance? 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 FFT appear to be appropriately remediated (mitigated)? Or For issues with open mitigation activities at the time of posting, include the information above and state the expected completion date. Date should be less than 12 months from date of posting. Explanation of why the length of time for completion is required. If the CE/FFT is associated with a formal Mitigation Plans, NERC Enforcement will ask the Regional Entity to explain the circumstances that prevented use of mitigation activities.	
4	For FFTs, an affidavit of completion signed by an officer with knowledge of the remediation and for FFTs and CEs other certification document/evidence was included.	
5	For ongoing mitigation, activities were successfully completed and certified.	
6	Consideration, if any, of the registered entity's internal compliance program. a) List any aspects of the ICP that were considered by the RE.	
7	The RE considered the compliance history when evaluating this issue. (applicable compliance history is 3 years from mitigation completion of prior issue to start of current issue). a) There have not 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.	
8	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 greater.	
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 14th day of November 2016.

/s/ Leigh Faugust

Leigh Faugust
Counsel for the North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability	**)**	
Corporation	**)**	**Docket No. 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 2016, in accordance with the January 16 Order. This variance information was

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[1] NERC was certified by FERC as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006) ("ERO Certification Order").

[2] *See North American Electric Reliability Corporation, Order Approving Settlement Agreement*, 142 FERC ¶ 61,042 (2013) ("January 16 Order").

[3] *Id.*

posted on NERC's website and reviewed at the October 27, 2016 open meeting of the NERC Finance and Audit Committee ("FAC"). The unaudited report was accepted by the NERC Board of Trustees at its meeting on November 2, 2016.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to:

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III. DISCUSSION OF SIGNIFICANT VARIANCES BETWEEN 2016 BUDGET AND PROJECTED ACTUAL 2016 RESULTS

The attached third quarter 2016 variance report compares actual (unaudited) financial results to NERC's budgeted expenditures as of September 30, 2016, and projected year-end 2016 financial results to NERC's total 2016 budgeted expenditures. NERC is providing additional discussion of significant variances between the projected actual (unaudited) year-end 2016 results and NERC's 2016 budget, 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 2016 results and the 2016 budget. For purposes of this discussion, 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. In addition, although not required by the Settlement Agreement, NERC is providing, for completeness, information in the attached report on actual cost variances less than budget of $500,000 or more by department, program area or major activity.

A. Compliance Assurance Program[4] and Information Technology

Actual 2016 direct expenses plus net fixed asset expenditures for the Compliance Assurance Program and Information Technology are projected at year end to be less than budgeted by $755k and $782k, respectively, as discussed on pages 4 and 5 of the third quarter 2016 variance report.

B. Reliability Risk Management

Actual 2016 direct expenses plus net fixed asset expenditures for the Reliability Risk Management department, which includes Performance Analysis, Event Analysis, and Situation Awareness, are projected to be $1.3M more than budgeted, primarily due to: (1) the allocation of additional staff resources to support coordination of data for the state of reliability reports, assistance with the BES exception resolution, and historical event data analysis ($500k); (2) the approved use of reserves for webTADS software related to user interface and data import

[4] The Compliance Assurance Program includes the Compliance Analysis, Certification and Registration Program and the Regional Entity Assurance and Oversight Program. These two operational programs were combined for reporting purposes in 2015.

enhancements ($113k); (3) the approved use of reserves for analysis software to collect and analyze system inertia data ($163k); (4) the development of Enterprise Reporting for GADS data ($411k), and, enhancements to the Bulk Electric System database ($111k), which were budgeted in IT but charged to the Performance Analysis program to align costs with the program utilizing the system. In the case of these last two items noted in item (4), there is no budget variance related to these items at the total company level, but rather the transfer of costs between departments that has generated an over, and offsetting under, budget variance in two departments.

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, 2016

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, 2016.

/s/ Meredith M. Jolivert

Meredith M. Jolivert
Counsel for North American Electric Reliability Corporation

ATTACHMENT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

North American Electric Reliability Corporation
Summary of Unaudited Results
September 30, 2016

Through September 30, 2016, NERC was $2.5M (4.9%) under its expense and fixed asset budget, including costs related to the Cyber Risk Information Sharing Program (CRISP). NERC is projecting to be approximately $926k (1.4%) over budget at year-end primarily due to higher than projected costs associated with the CRISP program which will be funded by CRISP participants.

Excluding the approved use of reserves, NERC was $2.7M (5.4%) under its expense and fixed asset budget and is projecting to be very close to budget at year-end ($290k or 0.4% over).

Actual vs Budget (YTD) and Projection vs Total Budget (including CRISP)

	Actual	Budget	Variance Over (Under)	%	Annual Projection	Annual Budget	Variance Over (Under)	%
TOTAL FUNDING	**$ 54,983,441**	**$ 50,921,373**	**$ 4,062,067**	**8.0%**	**$ 68,234,109**	**$ 67,502,155**	**$ 731,953**	**1.1%**
EXPENSES and FIXED ASSETS								
PERSONNEL EXPENSES	$ 28,494,940	$ 28,138,788	$ 356,152	1.3%	$ 37,695,509	$ 37,283,807	$ 411,702	1.1%
MEETINGS, TRAVEL and CONFERENCE CALLS	2,598,921	2,692,948	(94,027)	-3.5%	3,593,803	3,620,286	(26,483)	-0.7%
CONSULTANTS and CONTRACTS	8,059,564	9,649,449	(1,589,885)	-16.5%	13,176,799	12,865,914	310,885	2.4%
RENT	2,415,855	2,290,716	125,139	5.5%	3,224,287	3,054,287	170,000	5.6%
OFFICE COSTS, PROFESSIONAL SERVICES and MISC.	4,177,878	4,681,064	(503,186)	-10.7%	6,006,969	6,341,372	(334,402)	-5.3%
OTHER NON-OPERATING EXPENSES	99,313	95,000	4,313	4.5%	100,668	110,000	(9,332)	-8.5%
FIXED ASSET PURCHASES (excluding depreciation)	2,183,134	2,933,250	(750,116)	-25.6%	4,314,606	3,911,000	403,606	10.3%
TOTAL EXPENSES and FIXED ASSETS	**$ 48,029,604**	**$ 50,481,215**	**$ (2,451,611)**	**-4.9%**	**$ 68,112,641**	**$ 67,186,665**	**$ 925,976**	**1.4%**
APPROVED USE of RESERVES	273,528	-	273,528		636,338	-	636,338	
TOTAL EXPENSES and FIXED ASSETS (excluding reserves)	**$ 47,756,077**	**$ 50,481,215**	**$ (2,725,139)**	**-5.4%**	**$ 67,476,303**	**$ 67,186,665**	**$ 289,638**	**0.4%**
FTEs	**194.45**	**192.48**	**1.97**	**1.0%**	**193.32**	**192.48**	**0.84**	**0.4%**

NERC VARIANCES - excluding CRISP

NERC was $1.9M (4.1%) under its expense and fixed asset budget and is projecting to be $227k (0.4%) over budget at year-end. The following expenditures, representing the approved or anticipated use of reserves, are expected to be mostly offset by reduced spending in other areas, as further explained below:

(1) Approved use of reserves for data analysis software to collect and analyze system inertia data;
(2) Approved use of reserves for enhancements to webTADS related to interface and data import;
(3) Approved use of reserves for SAFNR-Data Modification;
(4) Approved use of reserves for IT contract support during periods of staff vacancies;
(5) Anticipated use of reserves for E-ISAC STIX/TAXII.

The following table and summary of variances by category reflect 2016 year-to-date (YTD) actual and projected results without CRISP. A summary of results for CRISP is provided on page 5.

Actual vs Budget (YTD) and Projection vs Total Budget
(Excluding CRISP)

	Actual	Budget	Variance Over (Under)	%	Annual Projection	Annual Budget	Variance Over (Under)	%
TOTAL FUNDING	**$ 44,966,836**	**$ 44,933,214**	**$ 33,622**	**0.1%**	**$ 59,562,309**	**$ 59,529,136**	**$ 33,172**	**0.1%**
EXPENSES and FIXED ASSETS								
PERSONNEL EXPENSES	$ 28,025,293	$ 27,580,214	$ 445,079	1.6%	$ 36,954,418	$ 36,542,135	$ 412,283	1.1%
MEETINGS, TRAVEL and CONFERENCE CALLS	2,572,238	2,640,856	(68,618)	-2.6%	3,546,348	3,550,831	(4,483)	-0.1%
CONSULTANTS and CONTRACTS	3,860,407	5,233,005	(1,372,598)	-26.2%	6,379,310	6,977,320	(598,010)	-8.6%
RENT	2,415,855	2,290,716	125,139	5.5%	3,224,287	3,054,287	170,000	5.6%
OFFICE COSTS, PROFESSIONAL SERVICES and MISC.	4,069,238	4,321,599	(252,362)	-5.8%	5,673,269	5,862,095	(188,825)	-3.2%
OTHER NON-OPERATING EXPENSES	99,313	95,000	4,313	4.5%	100,668	110,000	(9,332)	-8.5%
FIXED ASSET PURCHASES (excluding depreciation)	2,125,092	2,858,250	(733,158)	-25.7%	4,256,564	3,811,000	445,564	11.7%
TOTAL	**$ 43,167,435**	**$ 45,019,640**	**$ (1,852,205)**	**-4.1%**	**$ 60,134,863**	**$ 59,907,668**	**$ 227,196**	**0.4%**
FTEs	**192.10**	**189.71**	**2.39**	**1.3%**	**190.55**	**189.71**	**0.84**	**0.4%**

Following is a brief summary of significant variances by major categories:

- Personnel expenses were over budget $445k (1.6%) resulting from an additional 2.39 (1.3%) more FTEs than budgeted. Personnel expenses are projected to be $412k (near 1%) over budget at year-end. This near-budget projection is based on current staffing assumptions and reflects a stabilizing work force resulting from the successful implementation of a hiring strategy to fill key resource needs and efforts to close the historic gap between budgeted and actual FTEs to reduce overall attrition. The 2016 personnel budget was based on 210 positions, reduced by a vacancy rate of 7.8% (accounting for attrition and timing of new hires).
- Consultants and Contracts expenses were under budget $1.4M (26.2%) and are projected to be $598k (8.6%) under budget at year-end. E-ISAC has a projected over budget variance that is related to the approved use of reserves for STIX/TAXII, a pilot project supported by the E-ISAC Members Executive Committee which is intended to enhance voluntary cyber risk information sharing. That projected over budget variance is offset by expected under budget variances in other departments, which are primarily due to: (1) lower costs related to implementation of risk-based compliance monitoring in Compliance Assurance; (2) lower costs for ERO application support in Information Technology; (3) lower costs for compensation consulting expenses in Human Resources; and (4) lower than budgeted costs in Accounting and Finance due to the use of internal resources in place of anticipated external resources to support NERC's Internal Audit function.

SUMMARY OF CONSULTANT AND CONTRACT EXPENSES BY DEPARTMENT

CONSULTANTS and CONTRACTS	Actual	Budget	Variance Over (Under)	Annual Projection	Annual Budget	Variance Over (Under)
COMPLIANCE ANALYSIS and CERTIFICATION	$ -	$ 37,503	$ (37,503)	$ -	$ 50,000	$ (50,000)
COMPLIANCE ASSURANCE	5,347	150,003	(144,656)	5,347	200,000	(194,653)
RELIABILITY ASSESSMENTS and SYSTEM ANALYSIS	261,208	431,253	(170,045)	442,425	575,000	(132,575)
RELIABILITY RISK MANAGEMENT	1,453,973	1,332,387	121,586	1,781,367	1,776,514	4,853
E-ISAC	278,497	497,502	(219,005)	886,756	663,335	223,421
TRAINING, EDUCATION & OPERATOR CERTIFICATION	358,567	506,853	(148,286)	706,400	675,800	30,600
GENERAL & ADMINISTRATIVE	65,710	60,003	5,707	80,000	80,000	-
POLICY and EXTERNAL AFFAIRS	10,332	11,250	(918)	15,000	15,000	-
INFORMATION TECHNOLOGY	883,375	1,571,004	(687,629)	1,845,046	2,094,671	(249,625)
HUMAN RESOURCES	356,484	412,497	(56,013)	418,078	550,000	(131,922)
FINANCE and ACCOUNTING	186,915	222,750	(35,835)	198,891	297,000	(98,109)
TOTAL (excluding CRISP)	**$ 3,860,407**	**$ 5,233,005**	**$ (1,372,598)**	**$ 6,379,310**	**$ 6,977,320**	**$ (598,010)**
CRISP	4,199,157	4,416,444	(217,287)	6,797,489	5,888,594	908,895
TOTAL CONTRACTS and CONSULTANTS	**$ 8,059,564**	**$ 9,649,449**	**$ (1,589,885)**	**$ 13,176,799**	**$ 12,865,914**	**$ 310,885**

- Rent expense was over budget $125k (5.5%) and projected to be $170k (5.6%) over budget at year-end due to higher than budgeted building maintenance and real estate taxes expense.
- Office Costs, Professional Services, and Miscellaneous expenses were collectively under budget $252k (5.8%) and projected to be $189k (3.2%) under budget at year-end, primarily due to lower than budgeted costs for outside counsel, which are included in professional services expenses.
- Fixed Asset Purchases (excluding depreciation) were under budget $733k (25.7%) due to timing of expenses compared to budget allocation. This category is projected to be over budget $446k (11.7%) at year-end, largely due to the GADS Wind project (originally budgeted in contracts and consultants but recognized in fixed assets) and the authorized use of reserves in connection with a data analysis software that collects and analyzes system inertia data.

SUMMARY OF VARIANCES BY PROGRAM

The following table reflects variances by department as of September 30, 2016.

DIRECT EXPENSES and NET FIXED ASSETS	2016 YTD Actual	2016 YTD Budget	Variance Over/(Under)	2016 Projection	2016 Budget	Variance Over/(Under)
RELIABILITY STANDARDS	$ 2,604,637	$ 2,766,223	$ (161,585)	$ 3,584,433	$ 3,678,708	$ (94,275)
COMPLIANCE ANALYSIS, CERTICATION and REGISTRATION	1,443,757	1,572,889	(129,132)	1,889,111	2,086,784	(197,673)
COMPLIANCE ASSURANCE	3,044,772	3,440,683	(395,911)	4,001,439	4,559,234	(557,794)
ENFORCEMENT	1,864,535	1,677,975	186,561	2,490,038	2,225,816	264,222
RELIABILITY ASSESSMENTS and SYSTEM ANALYSIS	2,835,084	2,565,756	269,328	3,715,376	3,392,571	322,805
RELIABILITY RISK MANAGEMENT	5,849,016	5,065,512	783,504	8,039,506	6,719,091	1,320,415
E-ISAC	3,372,412	3,535,929	(163,518)	4,921,207	4,742,862	178,345
TRAINIING, EDUCATION and OPERATOR CERTIFICATION	1,341,032	1,549,032	(208,001)	2,024,283	2,060,167	(35,884)
GENERAL and ADMINISTRATIVE and EXECUTIVE	6,220,140	5,977,420	242,720	8,132,717	8,024,564	108,153
POLICY and EXTERNAL AFFAIRS	1,544,456	1,401,888	142,568	2,053,889	1,856,747	197,142
LEGAL and REGULATORY	2,337,659	2,610,899	(273,240)	3,234,120	3,465,966	(231,846)
INFORMATION TECHNOLOGY	7,130,939	9,134,010	(2,003,071)	11,374,748	12,156,674	(781,926)
HUMAN RESOURCES	903,862	1,134,773	(230,910)	1,221,116	1,510,177	(289,060)
FINANCE and ACCOUNTING	2,675,134	2,586,651	88,482	3,452,879	3,428,307	24,572
TOTAL (excluding CRISP)	**$ 43,167,435**	**$ 45,019,640**	**$ (1,852,205)**	**$ 60,134,863**	**$ 59,907,668**	**$ 227,196**

Following is a brief summary of significant variances:

- Reliability Standards; Compliance Analysis, Certification and Registration; Compliance Assurance – Under budget YTD and projected to be under budget at year-end primarily due to resource allocations and timing of new hires, and lower than budgeted outside contract support related to risk-based compliance monitoring, as noted above.
- Enforcement – Over budget YTD and projected to be over budget at year-end due to lower personnel attrition, as well as enhancements to the current CRATS database that was budgeted in 2015 but not completed until 2016. Funding for this project was reserved in the Future Obligations Reserve at the end of 2015.
- Reliability Assessments and System Analysis – Over budget YTD and projected to be over budget at year-end due to the allocation of additional resources to support ongoing program activities in specific departments within this program area.
- Reliability Risk Management (includes Event Analysis, Performance Analysis, and Situation Awareness departments) – Over budget YTD and expected to be over budget at year-end primarily due to (1) allocation of additional staff resources to support ongoing program activities, (2) the approved use of reserves for enhancements to webTADS related to interface and data import, and (3) development of Enterprise Reporting for GADS data, which was budgeted in IT but charged to the Performance Analysis program to align costs with the program utilizing the system.
- E-ISAC – Projected to be over budget at year-end due to the planned use of reserves for STIX/TAXII.

- Information Technology – Under budget year-to-date and projected to be under budget at year-end. The under budget variance is related to ERO Application development costs that are budgeted in IT but recorded in the programs utilizing the applications. The 2016 budget included $1.5M in ERO Applications, of which $1.2M was actually spent or expected to be spent. Approximately $650k of that actual spend has been allocated from the IT department to the relevant operating programs utilizing the application.
- Human Resources – Under budget year-to-date and projected to be under budget at year-end due to lower than budgeted outside compensation and general HR consulting services.

BOARD OF TRUSTEES EXPENSES

Board of Trustees expenses were under budget YTD by $73k (5.8%) and expected to be approximately on budget at year-end.

Board of Trustee Expenses	Actual	Budget	Variance Over (Under)	%
Meetings and Travel Expenses				
Quarterly Board Meetings and Conference Calls	$ 145,685	$ 185,000	$ (39,315)	-21.3%
Trustee Travel	86,617	118,000	(31,383)	-26.6%
Total Board of Trustees Meetings and Travel Expenses	**$ 232,303**	**$ 303,000**	**$ (70,697)**	**-23.3%**
Professional Services				
Independent Trustee Fees	841,564	844,767	(3,203)	-0.4%
Trustee Search Fees	101,134	100,000	1,134	0.0%
Total Board of Trustee Professional Services Expenses	**$ 942,698**	**$ 944,767**	**$ (2,069)**	**-0.2%**
Total Board of Trustee Expenses	**$ 1,175,001**	**$ 1,247,767**	**$ (72,766)**	**-5.8%**

CRISP VARIANCES (including indirect expenses and allocation of fixed assets)

CRISP was $723k (12.1%) under budget YTD and is projected to be $699k (8.8%) over budget at year-end primarily due to the additional costs associated with start-up expenses for new participants not originally included in the budget. These additional start-up costs will be funded by the new CRISP participants.

	Actual	Budget	Variance Over (Under)	%	Annual Projection	Annual Budget	Variance Over (Under)	%
TOTAL FUNDING	**$ 10,016,604**	**$ 5,988,160**	**$ 4,028,445**	**67.3%**	**$ 8,671,800**	**$ 7,973,019**	**$ 698,781**	**8.8%**
EXPENSES and FIXED ASSETS								
PERSONNEL EXPENSES	$ 469,647	$ 558,574	$ (88,927)		$ 741,091	$ 741,671	$ (580)	
MEETINGS, TRAVEL and CONFERENCE CALLS	26,683	52,092	(25,409)		47,455	69,455	(22,000)	
CONSULTANTS and CONTRACTS	4,199,157	4,416,444	(217,287)		6,797,489	5,888,594	908,895	
OFFICE COSTS, PROFESSIONAL SERVICES and MISC.	108,640	359,465	(250,824)		333,700	479,277	(145,577)	
FIXED ASSET PURCHASES (excluding depreciation)	58,042	75,000	(16,958)		58,042	100,000	(41,958)	
INDIRECT EXPENSES and ALLOCATION OF FIXED ASSETS	397,276	520,516	(123,240)		694,022	694,022	(0)	
TOTAL EXPENSES and FIXED ASSETS	**$ 5,259,445**	**$ 5,982,091**	**$ (722,646)**	**-12.1%**	**$ 8,671,800**	**$ 7,973,020**	**$ 698,779**	**8.8%**

OPERATING RESERVES – Current Balances

The balance in working capital and operating reserves YTD was $14.8M, which was $6.5M higher than budget. The increase was primarily due to higher CRISP reserves, which increased $4.8M due to timing differences between receipt of third-party funding for CRISP and expenses incurred throughout the year.

				September 30, 2016 Reserve Balances				
	Actual	Budget	Variance Over (Under)	Future Obligations Reserve	Operating Contingency Reserve	System Operator Reserves	***CRISP Reserves	Assessment Stabilization Reserve
2016 Beginning Reserve Balances	**$ 6,075,782**	**$ 6,313,523**	**$ (237,741)**	**$ 3,431,795**	**$ 1,213,419**	**$ 930,568**	**$ 500,000**	
Change in Reserves from Current Year Operations								
Change in Reserves from budgeted operations	7,516,657	440,158	7,076,499	-	2,787,662	(28,165)	4,757,160	
Approved use of reserves	(562,820)	-	(562,820)	(289,293)	(273,528)			
Capital Financing								
Proceeds from Financing Activities (non-current only)	589,375		589,375		589,375			
Debt Service	(758,190)	(703,333)	(54,856)		(758,190)			
Other adjustments to reserves**	1,923,647	2,271,000	(347,353)	(347,353)	-			2,271,000
Reserve Balance	**$14,784,451**	**$ 8,321,348**	**$ 6,463,104**	**$ 2,795,149**	**$ 3,558,740**	**$ 902,403**	**$ 5,257,160**	**$ 2,271,000**

*** Represents transactions recorded only on the Statement of Financial Position (balance sheet) and do not impact the Statement of Activities (income statement), including recording of capitalized leases, amortization of future obligations and funding the 457f plan.*

**** Represents $500k of insurance reserves, plus 2016 CRISP funding billed, net of 2016 actual YTD expenses.*

OPERATING RESERVES – Year-End Projection

The current year-end projection in total operating reserves is $8.4M, including $2.2M in the Operating Contingency Reserve (OCR) and $2.3M in the Assessment Stabilization Reserve (ASR).

OCR: The 2016 projected ending balance is above the assumed starting balance of $1.7M in the 2017 budget. The 2017 budget included additional funding for the OCR of $500k and an ending balance for 2017 of $2.2M. Therefore, NERC is currently tracking to be above the reserve target to start the 2017 budget year.

The following items reflect the anticipated or authorized use of reserves during 2016:

- E-ISAC STIX/TAXII project, which was not yet defined as of the 2016 budget approval (anticipated)
- Data analysis software to collect and analyze system inertia data (authorized - $172k)
- Enhancements to webTADS related to interface and data support (authorized - $113k)
- SAFNR data modification (authorized - $50k)
- IT contract support during periods of staff vacancies (authorized - $52k)

ASR: The 2016 projected ending balance agrees to the projected beginning balance for the 2017 budget. The 2017 budget anticipates $500k in penalties to be deposited in the ASR and the use of $1.1M in ASR funds to offset 2017 assessments. The ending ASR balance for 2017 is projected and budgeted to be $1.7M.

				2016 Projected Year End Reserve Balances				
	2016 Projection	2016 Budget	Variance Over (Under)	Future Obligations Reserve	Operating Contingency Reserve	System Operator Reserves	***CRISP Reserves	Assessment Stabilization Reserve
2016 Beginning Reserve Balances	$ 6,075,782	$ 6,313,523	$ (237,741)	$ 3,431,796	$ 1,213,419	$ 930,568	$ 500,000	$ -
Change in Reserves from Current Year Operations								
Change in Reserves from budgeted operations	1,047,098	315,490	731,608		1,310,268	(263,170)	-	
Approved use of reserves	(925,631)	-	(925,631)	(289,293)	(636,338)			
Capital Financing								
Proceeds from Financing Activities (non-current only)	1,391,375	1,000,000	391,375		1,391,375			
Debt Service	(1,044,253)	(1,055,000)	10,747		(1,044,253)			
Other adjustments to reserves**	1,806,132	2,170,614	(364,482)	(464,868)	-			2,271,000
Reserve Balance	$ 8,350,504	$ 8,744,627	$ (394,123)	$ 2,677,634	$ 2,234,473	$ 667,398	$ 500,000	$ 2,271,000

*** Represents transactions recorded only on the Statement of Financial Position (balance sheet) and do not impact the Statement of Activities (income statement), including recording of capitalized leases, amortization of future obligations and funding the 457f plan.*

**** Represents $500k of insurance reserves.*

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Statement of Activities and Fixed Assets Budget
(Unaudited)
For the period ended 09/30/2016

	Actual	Budget	Variance Over (Under)	%	Annual Projection	Annual Budget	Variance Over (Under)	%
Funding								
Assessments	$ 42,811,092	$ 42,811,092	-		$57,081,445	$57,081,445	$ -	
Assessment Stabilization Reserves - Penalties	1,439,000	1,439,000	-		1,439,000	1,439,000	-	
Assessment Stabilization Reserves - Non-Penalties	-	-	-		-	-	-	
Third-Party Funding (CRISP)	9,150,333	5,123,053	4,027,280		7,528,287	6,830,738	697,549	
Testing	1,323,760	1,400,976	(77,216)		1,867,972	1,867,972	-	
Services & Software	41,000	37,502	3,498		50,000	50,000	-	
Workshop Fees	192,970	107,500	85,470		231,304	230,000	1,304	
Interest	25,083	2,250	22,833		35,898	3,000	32,898	
Miscellaneous	202	-	202		202	-	202	
Total Funding	$ 54,983,441	$ 50,921,373	$ 4,062,067	8.0%	$ 68,234,109	$ 67,502,155	$ 731,953	1.1%
Expenses								
Personnel Expenses								
Salaries	$ 22,140,766	$ 21,663,383	$ 477,384		$29,425,809	$28,842,336	$ 583,473	
Payroll Taxes	1,524,153	1,593,151	(68,998)		1,785,932	1,871,367	(85,435)	
Employee Benefits	2,739,387	2,684,520	54,867		3,622,484	3,579,280	43,204	
Savings & Retirement	2,090,634	2,197,735	(107,101)		2,861,284	2,990,823	(129,539)	
Total Personnel Expenses	$ 28,494,940	$ 28,138,788	$ 356,152	1.3%	$ 37,695,509	$ 37,283,807	$ 411,702	1.1%
Meeting Expenses								
Meetings	$ 672,841	$ 800,113	$ (127,272)		$ 1,130,868	$ 1,096,500	$ 34,368	
Travel	1,765,553	1,652,832	112,721		2,242,955	2,203,786	39,169	
Conference Calls	160,527	240,003	(79,476)		219,980	320,000	(100,020)	
Total Meeting Expenses	$ 2,598,921	$ 2,692,948	$ (94,027)	-3.5%	$ 3,593,803	$ 3,620,286	$ (26,483)	-0.7%
Operating Expenses								
Consultants and Contracts	$ 8,059,564	$ 9,649,449	$ (1,589,885)		$13,176,799	$12,865,914	$ 310,885	
Rent & Improvements	2,415,855	2,290,716	125,139		3,224,287	3,054,287	170,000	
Office Costs	2,455,007	2,846,714	(391,707)		3,594,545	3,795,572	(201,027)	
Professional Services	1,711,941	1,806,975	(95,034)		2,371,922	2,509,300	(137,378)	
Miscellaneous	10,930	27,375	(16,445)		40,502	36,500	4,002	
Depreciation	1,809,122	1,981,467	(172,345)		2,614,736	2,641,943	(27,207)	
Total Operating Expenses	$ 16,462,418	$ 18,602,696	$ (2,140,278)	-11.5%	$ 25,022,792	$ 24,903,515	$ 119,276	0.5%
Other Non-Operating Expenses	$ 99,313	$ 95,000	$ 4,313	4.5%	$ 100,668	$ 110,000	$ (9,332)	-8.5%
Indirect Expenses	$ -	$ -	$ -		$ -	$ -	$ -	
Total Expenses	$ 47,655,592	$ 49,529,432	$ (1,873,841)	-3.8%	$ 66,412,771	$ 65,917,608	$ 495,163	0.8%
Net Change in Assets	**$ 7,327,849**	**$ 1,391,941**	**$ 5,935,908**	**426.4%**	**$ 1,821,337**	**$ 1,584,547**	**$ 236,790**	**14.9%**
Fixed Assets								
Depreciation	$ (1,809,122)	$ (1,981,467)	$ 172,345		$ (2,614,736)	$ (2,641,943)	$ 27,207	
Computer & Software	1,798,213	1,760,250	37,963		2,800,934	2,347,000	453,934	
Furniture & Fixtures	-	-	-		-	-	-	
Equipment	384,921	1,173,000	(788,079)		1,513,672	1,564,000	(50,328)	
Leasehold Improvements	-	-	-		-	-	-	
	-	-	-		-	-	-	
Allocation of Fixed Assets	-	-	-		-	-	-	
Incr(Dec) in Fixed Assets	**$ 374,012**	**$ 951,783**	**$ (577,771)**	-60.7%	**$ 1,699,870**	**$ 1,269,057**	**$ 430,813**	33.9%
Total Budget (Expenses plus Incr(Dec) in Fixed Assets)	**$ 48,029,604**	**$ 50,481,215**	**$ (2,451,611)**	**-4.9%**	**$68,112,641**	**$67,186,665**	**$ 925,976**	**1.4%**
Change in Operating Reserves (Total Funding less Total Budget)	**6,953,837**	**440,158**	**6,513,678**	**1479.8%**	**121,468**	**315,490**	**(194,022)**	
FTE's	**194.45**	**192.48**	**1.97**	**1.0%**	**193.32**	**192.48**	**0.84**	**0.4%**

NORTH AMERICAN ELECTRIC RELIABILITY COPORATION
STATEMENT OF FINANCIAL POSITION
(Unaudited)

	Unaudited 9/30/2016	Audited 12/31/2015	Working Capital and Operating Reserves 9/30/2016	Working Capital and Operating Reserves 12/31/2015
ASSETS				
Cash	$ 45,407,645	$ 40,308,955	$ 45,407,645	$ 40,308,955
Accounts receivable, net of allowance for uncollectible accounts of $0	13,522,676	3,986,346	13,522,676	3,986,346
Prepaid expenses and other current assets	1,561,602	1,291,805	1,561,602	1,291,805
Security deposit	125,416	125,416		
457(b) – Non-Qualified Deferred Compensation	744,439	744,438		
457(f) - Non-Qualified Def Comp	473,741	271,200		
Property and equipment	8,621,340	8,301,731		
Total Assets	$ 70,456,859	$ 55,029,891		
LIABILITIES AND NET ASSETS				
Liabilities				
Current Portion				
Accounts payable and accrued expenses (includes vacation accrual)	$ 3,373,771	$ 5,326,723	$ (3,373,771)	$ (5,326,723)
Accured incentive compensation	3,687,008	4,721,278	(3,687,008)	(4,721,278)
Deferred rent-current	377,752	322,016	(377,752)	(322,016)
Deferred compensation - current	6,818	-	(6,818)	-
Capital lease obligations - current	64,728	64,728	(64,728)	(64,728)
Accrued retirement liabilities	1,514,807	1,878,830	(1,514,807)	(1,878,830)
Debt service - current portion	1,038,940	744,253	(1,038,940)	(744,253)
Deferred income	14,356,939	7,961,316	(14,356,939)	(7,961,316)
Deferred revenue - CRISP	-	2,508,514	-	(2,508,514)
Regional assessments	20,786,709	12,273,666	(20,786,709)	(12,273,666)
Total Current Portion	$ 45,207,472	$ 35,801,324		
Long-Term Portion				
Deferred compensation[1]	1,132,171	1,038,350		
Long-Term Debt	511,497	680,311		
Penalties-Assessments stabilization	2,271,000	-		
Deferred Rent-non-current	3,119,263	3,412,298		
CRISP Insurance Reserve	500,000	500,000		
Capital lease obligations - non-current	151,752	151,752		
Total Long-Term Portion	$ 7,685,682	$ 5,782,711		
Total Liabilities	$ 52,893,154	$ 41,584,035		
Net Assets - unrestricted	$ 17,063,705	$ 9,735,856		
Net Assets - restricted	500,000	3,710,000	(500,000)	(3,710,000)
Total Liabilities and Net Assets	$ 70,456,859	$ 55,029,891	$ 14,784,451	$ 6,075,782

[1]Includes 457b and 457f liabilities, life insurance for former executive, and retiree medical

Working Capital and Operating Reserves	**$ 14,784,451**	**$ 6,075,782**

Financial Covenants	
1 - WC & OR Balance to Debt Service Ratio > 1.2 to 1.0 (Working Capital / Debt Service)	14.23
2 - Liquidity to Debt Service Ratio > 1.5 to 1.0* (= Cash - Regional Assessments - Restricted Net Assets)	23.22

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)**	**Docket No. RR16-___-000**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF AMENDMENTS TO THE FLORIDA RELIABILITY COORDINATING COUNCIL REGIONAL RELIABILITY STANDARD DEVELOPMENT PROCESS MANUAL

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November 10, 2016

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ATTACHMENT 3: Florida Reliability Coordinating Council Regional Reliability Standard Development Process Manual Revisions Summary Document

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RR16-___-000**

PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF AMENDMENTS TO THE FLORIDA RELIABILITY COORDINATING COUNCIL REGIONAL RELIABILITY STANDARD DEVELOPMENT PROCESS MANUAL

Pursuant to Section 215(e)(4) of the Federal Power Act ("FPA")[1] and Section 39.10 of the regulations of the Federal Energy Regulatory Commission ("Commission"),[2] the North American Electric Reliability Corporation ("NERC")[3] requests Commission approval of the revised Florida Reliability Coordinating Council, Inc. ("FRCC") Regional Reliability Standards Development Process Manual ("SDPM"). The FRCC SDPM is a "Regional Entity Rule" as defined in 18 C.F.R. § 39.10, and in accordance with 18 C.F.R. § 39.10, amendments to a "Regional Entity Rule" require Commission approval.[4]

As described in greater detail in Section II of this Petition, FRCC comprehensively revised its SDPM to improve upon and clarify its standard develop process as well as establish consistency with NERC's and the other Regional Entities' processes. The NERC Board of Trustees approved the revised FRCC SDPM at its November 2, 2016 meeting.

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1 16 U.S.C. § 824o (2012).

2 18 C.F.R. § 39.10 (2016).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

4 Pursuant to the Commission's November 2, 2015 and March 23, 2016 orders in Docket No. RR15-12, Regional Entity standard development procedures are no longer maintained as an exhibit to the Regional Delegation Agreements. NERC maintains an up-to-date copy of each Regional Entity's standard development procedure on its website at: http://www.nerc.com/AboutNERC/Pages/Regional-Entity-Delegation-Agreements.aspx.

Attachments 1 and 2 to this Petition are clean and redlined versions, respectively, of the proposed revised FRCC SDPM. As the redline changes are extensive, **Attachment 3** contains a section-by-section comparison of some of the more significant standard development process changes from the current FRCC SDPM to the revised FRCC SDPM to assist the Commission in reviewing the proposed revisions.

I. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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II. PROPOSED FRCC SDPM

The currently effective version of the FRCC SDPM is Version 0 developed in 2007 and approved by FERC on March 21, 2008.[5] In the intervening years, numerous improvements have been made to the NERC Standard Processes Manual and other Regional Entity standard development processes. The proposed amendments to the FRCC SDPM are intended to align the FRCC SDPM with the improvements made to those other processes and to clarify roles, responsibilities, and processes for standards development. As a preliminary matter, the FRCC SDPM has been revised to reflect that the FRCC Regional Entity Committee and Compliance Forum ("RECCF") exercises oversight authority responsibilities with regards to the FRCC

[5] *N. Am. Elec. Reliability Corp.*, 122 FERC ¶ 61,245 (2008).

SDPM, consistent with FRCC Bylaws revisions approved by the Commission in 2015.[6] The other proposed amendments revise the FRCC SDPM to accomplish a number of objectives, including:

- Incorporation of the results-based standards principles and NERC standard template.
- Inclusion of concurrent posting periods, to significantly reduce the length of time required for standards development.
- Addition of clarifying details surrounding the development and approval of Violation Severity Levels and Violation Risk Factors and the responsibilities and roles of participants in the FRCC process.
- Addition of a new FRCC Regional Reliability Standard development process flowchart.
- Updates to the Standard Authorization Request document to incorporate functional entity changes and addition of clarifying language.
- Updates to the format of the document.

The discussions in the following subsections describe the proposed amendments to the FRCC SDPM.

A. Table of Contents

The original Table of Contents for the FRCC SDPM is removed and replaced with a new Table of Contents that reflects the renumbering and reformatting of the FRCC SDPM.

B. Section 1.0 - Purpose

Section I – Introduction and Background in the current FRCC SDPM has been reorganized. The material formally contained under the subheading of *Purpose* in Section I of the current FRCC SDPM has been renumbered in the proposed FRCC SDPM as Section 1.0 – Purpose. Minor changes have been made to the text of this section to capitalize the terms Electric Reliability Organization and Reliability Standard.

[6] *N. Am. Elec. Reliability Corp.*, Docket No. RR15-3-000 (Jan. 13, 2015) (delegated letter order).

The FRCC Regional Reliability Standard Principles currently contained in Section I – Introduction and Background have been moved, with modifications as discussed below, into Section 3.1 of the revised FRCC SDPM.

C. Section 2.0 - Background

The revised FRCC SDPM adds a new background material section that contains information regarding FRCC's responsibilities and delegated authority. This section also clarifies that FRCC regional standards only apply to the FRCC footprint.

D. Section 3.0 - FRCC Regional Reliability Standards Development Process

The revised FRCC SDPM reorganizes and renumbers information regarding the process steps, roles, standard elements, and guiding principles for the development of FRCC Regional Reliability Standards under the FRCC SDPM to Section 3.0 – FRCC Regional Reliability Standards Development Process. A summary of the process and other changes is provided below. A comparison of the current to proposed process steps is provided in Attachment 3 to this Petition.

1. Section 3.1- FRCC Regional Reliability Standards Principles

As noted above, the FRCC Regional Reliability Standards Principles have been moved from Section I – Introduction and Background in the current FRCC SDPM to Section 3.1 of the revised FRCC SDPM. The following principles have been added to the revised FRCC SDPM, consistent with the essential attributes of NERC's Reliability Standards Processes:[7] (i) voting, which provides that the FRCC process shall have a balance of interests and diverse participation shall be encouraged; (ii) notification of standards development; (iii) transparency; (iv) consideration of views and objections; (v) consensus building; (vi) consensus vote; and (vii)

[7] *See* Standard Processes Manual, Appendix 3A to the NERC Rules of Procedure at Section 1.4, *available at* http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx

timeliness. In addition, the principle of open participation has been revised to provide additional language to clarify that there are no barriers that would prevent any party or entity from participating in the FRCC regional standard development process.

2. Section 3.2 - FRCC Regional Reliability Standard Elements

The provisions contained in Section II of the current FRCC SDPM – FRCC Regional Reliability Standard Definition, Characteristics, and Elements have been moved to Section 3.2 of the revised FRCC SDPM. In Section 3.2.1, the currently-effective definition of Reliability Standard has been added. Sections 3.2.2 – Reliability Principles and 3.2.3 – Market Principles expand upon the obligation to develop Regional Reliability Standards that are consistent with NERC's Reliability Principles as well as NERC's Market Interface Principles. Section 3.2.5 – Types of Reliability Requirements defines the type of reliability requirements consistent with Section 2.4 of the NERC Standard Processes Manual, including: (i) performance-based requirements; (ii) risk-based requirements; and (iii) capability-based requirements. Section 3.2.6 – Elements of a Reliability Standard lists and explains the elements on an FRCC Regional Reliability Standard in a manner that is more consistent with how that information is presented in Section 2.5 of the NERC Standard Processes Manual. The introductory language to the section contains revisions that are intended to improve the text and style of the language.

Section 3.2.7 – Nomination, Modification, or Withdrawal of a Reliability Standard has been revised to introduce the use of a Standard Authorization Request (SAR) in a more direct manner.

3. Section 3.3 - Responsibilities and Roles in the FRCC Regional Reliability Standard Development Process

Section 3.3 contains a number of clarification improvements and updates to the responsibilities and roles of participants in the FRCC standard development process.

Section 3.3.1 – FRCC Board of Directors identifies more specifically FRCC Board of Directors responsibilities, including the responsibility to approve Violation Risk Factors and Violation Severity Levels for FRCC Regional Reliability Standards.

Section 3.3.2 – Registered Ballot Body contains several non-substantive revisions and revisions to clarify what the Registered Ballot Body votes to approve.

Section 3.3.3 – Ballot Pool contains several non-substantive revisions to improve the readability and clarity of the section.

Section 3.3.4 – FRCC Regional Entity Committee and Compliance Forum (RECCF) reflects that the responsibilities formerly held by the FRCC Regional Entity Operating Committee and Regional Entity Planning Committee for oversight of the FRCC standard development process are now exercised by the FRCC RECCF. Section 3.4 has been updated to identify specific responsibilities associated with the oversight activities of the FRCC RECCF.

Section 3.3.5 – FRCC Standards and Registration Staff is revised to include staff responsibilities that are not specifically identified in the current FRCC SDPM, such as responsibilities associated with Violation Risk Factor and Violation Severity Level development, staff reviews of standard development documents, and coordination with the FRCC RECCF.

Section 3.3.6 – Drafting Teams includes additional language regarding the responsibilities associated with the establishment of standard drafting teams and the responsibilities of those standard drafting teams. For example, the revised FRCC SDPM identifies responsibilities associated with drafting of the standard (or definition) and implementation plans, the use of informal and formal consensus building through participation in various industry forums, and so on.

Section 3.3.7 – Governmental Authorities is new in the revised FRCC SDPM and is intended to clarify the role of the applicable governmental authority (i.e. the Commission) to approve FRCC Regional Reliability Standards.

Section 3.3.8 – FRCC Committees, Subcommittees, Working Groups, and Task Forces is updated to refer to the oversight role of the FRCC RECCF. In addition, the section is revised to clarify the relationships between the FRCC RECCF and the FRCC's technical committees, subcommittees, working groups, and task forces; specifically, that these technical groups may assist with providing technical justification for developing of new Regional Reliability Standards and guidance in overseeing any field tests.

Section 3.3.9 – FRCC Compliance Staff contains minor grammatical changes.

4. Section 3.4 - Process for Developing an FRCC Regional Reliability Standard

Section 3.4 describes the specific process steps for developing an FRCC Regional Reliability Standard. Numerous clarification and process improvements have been made in the revised FRCC SDPM, and the language has been updated throughout to reflect the oversight role of the FRCC RECCF.

Section 3.4.1 (Step 1) introduces language to identify the use of a standard authorization request as the mechanism to start standard development, and additional language is provided to clarify the roles of FRCC staff.

Section 3.4.2 (Step 2) contains minor revisions requiring FRCC staff to notify the FRCC RECCF when a standard request is received.

Section 3.4.3 (Step 3) adds specificity with respect to when standard authorization requests are posted for formal and informal comment periods and drafting team obligations to respond to comments.

Section 3.4.4 (Step 4) provides additional information regarding the FRCC RECCF's responsibilities associated with the disposition of individual standard authorization requests and the solicitation and selection of standard drafting team members.

Section 3.4.5 (Step 5) contains a number of improvements intended to clarify roles and responsibilities and provide for the development of quality standards. The revisions contained in this section provide guidance to the drafting team on standard or definition development, including ensuring that all standards are within the scope of their associated standard authorization request, include all elements, and meet the quality attributes identified in NERC's *Ten Benchmarks for Excellent Reliability Standards* and the criteria for governmental approval. The revisions in this section also introduce FRCC staff responsibilities regarding Violation Risk Factors and Violation Severity Levels, identify methods for conducting industry feedback, and add a requirement to conduct quality reviews prior to posting.

Section 3.4.6 (Step 6) contains revisions clarifying roles and responsibilities and specifying who shall receive notice when a second draft of a standard is posted for comment.

Section 3.4.7 (Step 7) contains revisions to provide for additional clarity regarding the establishment of the ballot pool and joining or withdrawing from the ballot pool.

Section 3.4.8 (Step 8) has been amended in several key respects. First, the process language has been updated to incorporate the use of concurrent posting periods (i.e., comment period, ballot pool formation, and initial ballot during the same time frame). These concurrent posting periods would reduce the time for standards development. Second, the revisions introduce the concept of non-binding polls of Violation Risk Factors and Violation Severity Levels. Lastly, the revisions clarify roles and responsibilities of FRCC staff and the standard

drafting team with respect to responding to stakeholder comments and initial/additional ballot results.

Section 3.4.9 (Step 9) contains updated process language to clarify and include a process step defining final ballot requirements. Guidance is provided to members of the ballot pool on the conduct of the final ballot, and language is added to reflect the involvement and responsibilities of the FRCC RECCF.

Section 3.4.10 (Step 10) contains revisions clarifying the FRCC Board of Directors' responsibilities associated with adoption of an FRCC Regional Reliability Standard and approval of the associated Violation Risk Factors, Violation Severity Levels, and implementation plans. The revised language contains guidance regarding the approval of Violation Risk Factors and Violation Severity Levels. Additionally, the responsibilities of FRCC staff are clarified.

Section 3.4.11 (Step 11) contains minor revisions regarding the submission of FRCC Regional Reliability Standards for NERC and FERC approval.

5. Section 3.5 - Special Procedures

Section V – Special Procedures of the current FRCC SDPM contains processes for urgent action development of standards, standards interpretations, and appeals. The processes for urgent action and appeals are carried forward with minor revisions into Section 3.5 of the revised FRCC SDPM.[8] New Section 3.5.2 – Regional Definition Development has been added to provide a process for the addition, modification, or retirement of regional definitions.

6. Section 3.6 - Maintenance of the FRCC Regional Reliability Standards and Process

Section 3.6 provides processes for revising the FRCC SDPM (Section 3.6.1) and for the

[8] The revised FRCC SDPM does not contain a process for interpretations. FRCC currently employs an "Information Request Procedure" which provides assistance to stakeholders in the understanding and application of FRCC Reliability Standards.

five-year review of FRCC Regional Reliability Standards (Section 3.6.2). These topics are currently addressed in brief form in the current FRCC SDPM in Section VI – Maintenance of the FRCC Regional Reliability Standards and Process. These sections are significantly expanded to provide additional clarification with respect to the process requirements and the role of FRCC staff in these areas. For example, Section 3.6.1 now provides for the posting and balloting of changes to the FRCC SDPM. Section 3.6.2 now provides for a "review team" for FRCC Regional Reliability Standards where there are no outstanding governmental directives or unresolved stakeholder issues associated with that standard. This section also provides processes for where the team recommends reaffirmation, modification, or withdrawal of an FRCC Regional Reliability Standard.

E. Section 4.0, References

Section 4.0 has been added to refer to documents that are referenced in the revised FRCC SDPM.

F. Section 5.0, Attachments

Section 5.0 has been added to formally list the attachments to the revised FRCC SDPM. The Attachments consist of the following: (i) Attachment A, the FRCC Regional Reliability Standard Authorization Form; (ii) Attachment B, Process Diagram; and (iii) Attachment C: Development of and Voting of the Registered Ballot Body.

Attachment A revises Appendix A to the current FRCC SDPM to require, in the standard authorization request form, a more detailed description of the industry need for a proposed standard. Additionally, updates have been made to the definitions of the functional entities. The basic flowchart in Appendix B to the current FRCC SDPM has been replaced in the revised FRCC SDPM with a more detailed process flowchart that describes the process steps and

approval flows. Attachment C in the revised FRCC SDPM is carried forward from Appendix C in the current FRCC SDPM. Revisions are made to Section 3 - Ballot Pool Voting to clarify that negative votes without comments, as well as abstentions, are not counted and to state which positions may be voted. This process revision was developed in response to a recommendation of the NERC Standard Process Input Group to "limit negative ballots without comment."[9] The requirement to submit comments with a negative vote in order for the vote to be counted is intended to encourage the submission of comments that will provide guidance to drafting teams as to how to revise their work to achieve a consensus standard and is consistent with similar provisions in the NERC Standard Processes Manual. This section has also been revised to provide a process by which a standard achieving a quorum with no negative votes with comments and at least two thirds approval in the initial ballot will be deemed approved by the ballot pool with no need for final ballot. This revision recognizes that the counted ballots in such a case would result in an approval percentage of 100%, and no further work by the drafting team would improve consensus.

G. Section 6.0 – Review and Modification History

A revision and modification log has been added to be consistent with the FRCC template for such documents.

III. FRCC AND NERC APPROVALS FOR THE PROPOSED AMENDMENTS

The revised FRCC SDPM was posted on the FRCC website for regional ballot body comments from January 25, 2016 through March 4, 2016. An initial ballot was conducted from February 22, 2016 through March 4, 2016. The comments received were reviewed by FRCC

[9] *See* NERC Member Representatives Committee Standards Process Input Group, *Recommendations to Improve the NERC Standards Development Process* (Apr. 2012), available at http://www.nerc.com/pa/Stand/Standards%20Processes%20Manual%20revisions%20SPIG%20Recommen/Standards_Process_Input_Group_04.24.12_ver_8_FINAL.pdf.

Staff and non-substantive revisions were made as appropriate. The document was posted for final ballot from April 12, 2016 through April 23, 2016, where it achieved a 100% quorum and 100% approval. The revised FRCC SDPM was approved by the FRCC Board of Directors on June 30, 2016.

The FRCC SDPM was posted on the NERC website for industry stakeholder comment from July 1, 2016 through August 15, 2016. Two sets of supportive responses and no comments were received. The NERC Board of Trustees approved the amendments to the FRCC SDPM at its November 2, 2016 meeting.

IV. CONCLUSION

NERC respectfully requests that the Commission approve the proposed amendments to the FRCC SDPM as shown in **Attachment 2** to this Petition.

Respectfully submitted,

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November 10, 2016

ATTACHMENT 1:

Amended Florida Reliability Coordinating Council Regional Reliability Standard Development Process Manual – Clean

FRCC REGIONAL RELIABILITY STANDARD DEVELOPMENT PROCESS MANUAL

FRCC-RE-STD-001

Effective Date: Month Day, Year

Version: 1

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TITLE	NAME	DATE
Version Author	Peter Heidrich	06/19/2015
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1.0 Purpose

This manual establishes the process for development, revision, withdrawal and approval of Florida Reliability Coordinating Council, Inc. (FRCC) Regional Reliability Standards for the FRCC Region. FRCC Regional Reliability Standards apply to the reliability planning and reliable operation of the Bulk Power System in the FRCC Region. Proposed FRCC Regional Reliability Standards shall be subject to approval by the North American Electric Reliability Corporation (NERC), as the Electric Reliability Organization (ERO) and by the Federal Energy Regulatory Commission (FERC) before becoming mandatory and enforceable under Section 215 of the Federal Power Act. FRCC Regional Reliability Standards, when approved by FERC, shall be made part of the body of the NERC Reliability Standards and shall be enforced upon all applicable bulk power system owners, operators and users within the FRCC Region, regardless of membership in the region.

The FRCC Regional Reliability Standards Development Process is based on providing an open and fair process that ensures all interested and affected parties have an opportunity to participate in the development of FRCC Regional Reliability Standards. Any entity (person, organization, company, government agency, individual, etc.) with a direct and material interest in the reliability of the FRCC Bulk Power System has a right to participate by: a) expressing a position and its basis, b) having that position considered, c) voting on and d) having the right to appeal.

2.0 Background

FRCC is responsible for promoting and assuring the reliability of the interconnected Bulk Power System in Peninsular Florida. FRCC carries out its mission through 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.

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, FRCC as a Regional Entity with delegated authority from NERC may propose regional standards to NERC for eventual enforcement within the FRCC region.

NERC Reliability Standards are comprised of both continent-wide and regional standards. The FRCC regional standards apply only to that part of the Eastern Interconnection within the FRCC geographical area.

3.0 FRCC Regional Reliability Standards Development Process

3.1 FRCC Regional Reliability Standard Principles

FRCC Regional Reliability Standards go beyond, add detail to, or implement the NERC Reliability Standards, or cover matters not addressed in the NERC Reliability Standards. FRCC Regional Reliability Standards shall not be inconsistent with or less stringent than the NERC Reliability Standards.

FRCC Regional Reliability Standards are based on the *NERC's Reliability Principles* and *Market Interface Principles*. Each FRCC Regional Reliability Standard shall enable or

support one or more of *NERC's Reliability Principles* and must accommodate competitive electricity markets by being consistent with *NERC's Market Interface Principles*.

The FRCC Regional Reliability Standard Development Process defines the fair and open process for development, revision, withdrawal and approval of FRCC Regional Reliability Standards for the FRCC Region and has the following characteristics:

Open Participation **–** Participation in the FRCC Regional Reliability Standards Development Process is open to all entities that are directly and materially affected by FRCC Reliability Standards or the reliability of the FRCC Bulk Power System. There shall be no financial barriers to participation and participation shall not be conditional upon membership in any organization, nor unreasonably restricted on the basis of technical qualifications or other such requirements. All FRCC Regional Reliability Standard Development meetings will be publically noticed on the FRCC website.

Balance **–** The FRCC Regional Reliability Standard Development Process shall have a balance of interests and shall not be dominated by any two interest categories, individuals, or organizations and no single interest category, individual, or organization shall be able to defeat a matter.

Voting **–** FRCC shall use a voting formula that allocates each industry sector an equal weight in determining the final outcome of any standard action. The FRCC Regional Reliability Standards Development Process shall have a balance of interests. Participants from diverse interest categories shall be encouraged to join the Registered Ballot Body and participate in the balloting process, with a goal of achieving balance between the interest categories. The Registered Ballot Body serves as the consensus body voting to approve each new or proposed Regional Reliability Standard, and/or definition.

Notification of standards development - FRCC shall distribute notices to each member of the Registered Ballot Body, and to each stakeholder who indicates a desire to receive such notices, for each action to create, revise, reaffirm, or withdraw a standard. Notices shall be distributed electronically, with links to the relevant information, and notices shall be posted on FRCC's Standards web page. All notices shall identify a readily available source for further information.

Transparency – The *FRCC Regional Reliability Standards Development Process* shall be transparent to the public.

Consideration of views and objections - Drafting teams shall give prompt consideration to the written views and objections of all participants, providing individualized written responses to those commenting during formal comment periods and those commenting as part of the balloting process. Drafting teams shall make an effort to resolve each objection that is related to the topic under review.

Consensus building - The process shall build and document consensus for each standard, both with regard to the need and justification for the standard and the content of the standard.

Consensus vote - FRCC shall use its voting process to determine if there is sufficient consensus to approve a proposed Reliability Standard, or definition. FRCC shall form a Ballot Pool for each standard action from interested members of its Registered Ballot Body. Approval of any standard action requires:

- A quorum, which is established by at least two thirds of the members of the Ballot Pool submitting a response with an affirmative vote, a negative vote, or an abstention; and

- A two-thirds majority of the weighted segment votes cast shall be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

Timeliness – Development of standards shall be timely and responsive to new and changing priorities for reliability of the FRCC Bulk Power System.

3.2 FRCC Regional Reliability Standard Elements

3.2.1 Definition

A FRCC Regional Reliability Standard defines certain obligations or requirements of all owners, operators and users of the FRCC Bulk Power System regardless of membership in the FRCC. The obligations or requirements must be material to reliability and measurable. A Reliability Standard is defined in the NERC Glossary of Terms used in NERC Reliability Standards (effective July 1, 2016) as:

> *A requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for Reliable Operation of the Bulk-Power System. The term includes requirements for the operation of existing Bulk-Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for Reliable Operation of the Bulk-Power System, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.*

FRCC Regional Reliability Standards go beyond, add detail to, or implement the NERC Reliability Standards, or cover matters not addressed in the NERC Reliability Standards. FRCC Regional Reliability Standards shall not be inconsistent with or less stringent than NERC Reliability Standards.

3.2.2 Reliability Principles

FRCC Regional Reliability Standards are based on the *NERC Reliability Principles* that define the foundation of reliability for North American Bulk Power Systems. Each FRCC Regional Reliability Standard shall enable or support one or more of the *NERC Reliability Principles*, thereby ensuring that each standard serves a purpose in support of reliability of the FRCC Bulk Power System. Each FRCC Regional Reliability Standard shall also be consistent with all of the *NERC Reliability Principles*, thereby ensuring that no standard undermines reliability through an unintended consequence.

3.2.3 Market Principles

Recognizing that Bulk Power System reliability and electricity markets are inseparable and mutually interdependent, all FRCC Regional Reliability Standards shall be consistent with the *NERC Market Interface Principles*. Consideration of the Market Interface Principles is intended to ensure that FRCC Regional Reliability Standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

3.2.4 Characteristics

A FRCC Regional Reliability Standard shall have the following characteristics:

Material to Reliability - A FRCC Regional Reliability Standard shall be material to the reliability of the FRCC Bulk Power System. If the reliability of the FRCC Bulk Power System could be compromised without a particular standard or by a failure to comply with that standard, then the standard is material to reliability.

Measurable - A FRCC Regional Reliability Standard shall establish technical or performance requirements that can be practically measured.

Relative to NERC Reliability Standards - A FRCC Regional Reliability Standard must go beyond, add detail to, or implement NERC Reliability Standards, or cover matters not addressed in NERC Reliability Standards.

3.2.5 Types of Reliability Requirements

Although FRCC Regional Reliability Standards have a common format and process, several types of Reliability Standards requirements may exist, each with a different approach to measurement:

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

Risk-based requirements define actions of entities that reduce a stated risk to the reliability of the Bulk Power System and can be measured by evaluating a particular product or outcome resulting from the required actions.

Capability-based requirements define capabilities needed to perform reliability functions and can be measured by demonstrating that the capability exists as required.

The body of FRCC reliability requirements, combined with the NERC reliability requirements, collectively provides a defense-in-depth strategy supporting reliability of the FRCC Bulk Power System.

3.2.6 Elements of a Reliability Standard

A FRCC Regional Reliability Standard includes many elements designed to work collectively to identify what entities must do to meet their reliability-related obligations as an owner, operator or user of the FRCC Bulk Power System. Elements that are considered mandatory and enforceable are identified below. The elements of a Reliability Standard include the following:

Title: A brief, descriptive phrase identifying the topic of the standard.

Number: A unique identification number assigned in accordance with a published classification system to facilitate tracking and reference to the standards.

Purpose: The reliability outcome achieved through compliance with the requirements of the standard.

Applicability (mandatory and enforceable): Provides clear identification of the functional classes of entities responsible for complying with the standard, noting any specific additions or exceptions.

If not applicable to the entire FRCC, then a clear identification of the portion of the FRCC Bulk Power System to which the standard applies will be made. Any limitation on the applicability of the standard based on electric facility requirements should be described.

Effective Dates (mandatory and enforceable): Identification of when each requirement becomes effective within the jurisdiction of the FRCC.

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

Measure: Provides identification of the evidence or types of evidence that may demonstrate compliance with the associated requirement. Each requirement shall have at least one measure. Each measure shall clearly refer to the requirement(s) to which it applies.

Evidence Retention: Identification, for each requirement in the standard, of the entity that is responsible for retaining evidence to demonstrate compliance, and the duration for retention of that evidence.

Application Guidelines: Guidelines to support the implementation of the associated standard.

Procedures: Procedures to support implementation of the associated standard.

Time Horizon: The time period related to when a requirement takes place or how much time there may be to mitigate a violation of the associated requirement.

Compliance Enforcement Authority: The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated standard.

Additional Compliance Information: Any other information related to assessing compliance such as the criteria or periodicity for filing specific reports.

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 FRCC Regional 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 FRCC Standards and Registration staff, at the same time as the associated Reliability Standard, but are not part of Reliability Standard. The FRCC Board of Directors is responsible for approving VRFs and VSLs.

Violation Risk Factors (VRFs): 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): 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.

3.2.7 Nomination, Modification, or Withdrawal of a Regional Standard

Any member of the FRCC, or group (i.e. committee, subcommittee, working group or task force) within the FRCC, shall be allowed to request that a FRCC Regional Reliability Standard be developed, modified, or withdrawn. Additionally, any interested party or any entity that is directly and materially affected by the reliability of the FRCC Bulk Power System shall be allowed to request that a FRCC Regional Reliability Standard be developed, modified, or withdrawn.

A FRCC Standard Authorization Request (SAR) is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified standards or the benefit of retiring one or more approved standards. Any entity or individual may propose the development of a new or modified standard, or may propose the retirement of a standard, by submitting a completed SAR to the FRCC Standards and Registration staff at FRCCStandard@frcc.com.

Each SAR that proposes a "new" standard, should be accompanied with a technical justification that includes, as a minimum, a discussion of the reliability-related impact of not developing the new standard, and a technical foundation document (e.g., research paper), when needed, to guide the development of the standard.

3.3 Responsibilities and Roles in the FRCC Regional Reliability Standard Development Process

3.3.1 FRCC Board of Directors

The FRCC Board of Directors (BOD) shall consider for adoption FRCC Regional Reliability Standards, definitions, and associated implementation plans that have been developed and approved by the processes identified in this manual. In addition, the board shall consider for approval, VRFs and VSLs associated with each approved standard. Once the Board adopts a FRCC Regional Reliability Standard, or definition, or once the Board approves VRFs or VSLs, the Board shall direct FRCC Standards and Registration staff to file the document(s) with NERC for approval with the applicable regulatory authorities.

3.3.2 Registered Ballot Body

The Registered Ballot Body votes to approve FRCC Regional Reliability Standards, definitions, and associated implementation plans. The Registered Ballot Body comprises all entities and individuals that qualify for one of the FRCC Industry Sectors as defined in Section 1.2 of the FRCC Bylaws, and are registered with FRCC as potential ballot participants in the voting on standards. FRCC membership is not a requirement to participate in the development of, and voting on, FRCC Regional Reliability Standards. Any entity or individual that has a material interest in the reliability of the FRCC Bulk Power System shall be allowed to register as potential ballot participants in the Registered Ballot Body. (See Attachment C) Each member of the Registered Ballot Body is eligible to join the Ballot Pool for each standard action.

3.3.3 Ballot Pool

Each standard action has its own Ballot Pool formed of interested members of the Registered Ballot Body. The Ballot Pool comprises those members of the Registered Ballot Body that respond to a pre-ballot survey participation request for that particular standard action. The Ballot Pool will vote to approve each standard action. The Ballot Pool remains in place until all balloting related to that standard action is complete.

3.3.4 FRCC Regional Entity Committee and Compliance Forum (RECCF)

The FRCC RECCF, a balanced stakeholder committee, is responsible for managing the standards processes for the development of standards, VRFs, VSLs, and definitions in accordance with this manual. The responsibilities of the FRCC RECCF are defined in detail in the committee scope document.

Per Section 3.4 of this manual, the FRCC RECCF has the right to remand work to a drafting team, to reject the work of a drafting team, or to accept the work of a drafting team. The FRCC RECCF may direct a drafting team to revise its work to follow the processes in this manual or to meet the criteria for the NERC's *Benchmarks for Reliability Standards*, or to meet the criteria for governmental approval, however the FRCC RECCF shall not direct a drafting team to change the technical content of a draft standard. The FRCC RECCF shall meet at regularly scheduled intervals (either in person, or by other means). FRCC RECCF meetings where topics related to the Standards Development Process are being discussed or acted on will be publically posted on the FRCC website.

3.3.5 FRCC Standards and Registration Staff

The FRCC Standards and Registration staff, led by the Manager of Standards and Registration, is responsible for administering FRCC's Reliability Standards Processes in accordance with this manual and adhering to the requirements identified in the *NERC Regional Reliability Standards Evaluation Procedure*. The FRCC Standards and Registration staff provides support to the FRCC RECCF in managing the standards processes and supporting the work of all drafting teams. The FRCC Standards and Registration staff work to ensure the integrity of the standards processes and consistency of quality and completeness of the Reliability Standards. The FRCC Standards and Registration staff facilitates all steps in the development of standards, definitions, and associated implementation plans. The FRCC Standards and Registration staff work with drafting teams in developing VRFs and VSLs for each standard.

The FRCC Standards and Registration staff shall coordinate a quality review of the "final draft" of the Reliability Standard, its implementation plan, and VRFs and VSLs to assess whether the documents are within the scope of the associated SAR, whether the standard is clear and enforceable as written, and whether the standard meets the criteria specified in the NERC and FERC guidelines. This review shall normally be completed within thirty (30)

calendar days[1] of receipt of the final version of the documents from the Standard Drafting Team (SDT). The detailed results of this review shall be provided to the SDT for consideration. The SDT shall consider the results of the quality review, decide upon appropriate changes, and recommend to the FRCC RECCF whether the documents are ready for formal posting and balloting.

If the FRCC RECCF agrees that the proposed Reliability Standard, implementation plan, and VRFs and VSLs pass this review, the FRCC RECCF shall authorize posting for a formal comment period, ballot (for the standard and implementation plan), and non-binding poll (for VRFs and VSLs) as soon as the work flow will accommodate.

If the FRCC RECCF finds that any of the documents do not meet the specified criteria, the FRCC RECCF shall remand the documents to the SDT for additional work.

If the standard is outside the scope of the associated SAR, the SDT shall be directed to either revise the standard so that it is within the approved scope, or submit a request to expand the scope of the approved SAR. If the standard is not clear and enforceable as written, or if the standard or its VRFs and/or VSLs do not meet the specified criteria, the standard shall be returned to the SDT with specific identification of any requirement that is deemed to be unclear or unenforceable as written.

The FRCC Standards and Registration staff is responsible for presenting standards, and definitions to the FRCC Board of Directors for adoption. When presenting standards-related documents to the FRCC Board of Directors for adoption or approval, the FRCC standards and Registration staff shall report the results of the associated stakeholder ballot, including identification of any unresolved minority stakeholder issues.

3.3.6 Drafting Teams

The FRCC RECCF shall appoint industry subject matter experts to drafting teams to work with stakeholders in developing and refining SARs, standards, VRFs, VSLs and definitions.

Each drafting team consists of a group of technical experts that work cooperatively with the support of the FRCC Standards and Registration staff. The technical experts provide subject matter expertise and guide the development of the technical aspects of the standard. The technical experts maintain authority over the technical details of the standard. Each drafting team appointed to develop a standard is responsible for following the processes identified in this manual from the inception of the assigned project through the final acceptance of that project by applicable governmental authorities.

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

Collectively, each drafting team will:

- Draft proposed language for the Reliability Standards, definitions, and associated implementation plans.
- Solicit, consider, and respond to comments related to the specific standards development project.
- Participate in industry forums to help build consensus on the draft Reliability Standards, definitions, and associated implementation plans.
- Assist in developing the documentation used to obtain approval and subsequent filing of the Reliability Standards, definitions and associated implementation plans.

The FRCC Standards and Registration staff shall provide a member to support the team with technical writing expertise and shall provide administrative support to the team, guiding the team through the steps in completing its project. The individuals provided by the FRCC Standards and Registration staff serve as advisors to the drafting team and do not have voting rights. The FRCC RECCF may also supplement the membership of a standard drafting team at any time to ensure the necessary competencies and diversity of views are maintained throughout the standard development effort. All drafting teams report to the FRCC RECCF.

3.3.7 Governmental Authorities

The Federal Energy Regulatory Commission (FERC) in the United States of America has the authority to approve each new, revised or withdrawn Reliability Standard, definition, VRF, and VSL following adoption or approval by the NERC Board of Trustees.

3.3.8 FRCC Committees, Subcommittees, Working Groups, and Task Forces

FRCC's technical committees, subcommittees, working groups, and task forces may provide technical research and analysis used to justify the development of new standards and may provide guidance, when requested by the FRCC RECCF, in overseeing field tests or collection and analysis of data. The technical committees, subcommittees, working groups, and task forces may provide feedback to drafting teams during both informal and formal comment periods.

The technical committees, subcommittees, working groups, and task forces share their observations regarding the need for new or modified standards or requirements with the FRCC Standards and Registration staff for use in identifying the need for new standards projects.

3.3.9 FRCC Compliance Staff

The FRCC Compliance staff provide input and comments during the standard development process to ensure the requirements are not ambiguous, that measures are clear and effective and that the compliance elements of a standard can be practically implemented.

3.4 Process for Developing an FRCC Regional Reliability Standard

3.4.1 Step 1 – Request a new FRCC Regional Reliability Standard or modification to, or withdrawal of an existing FRCC Regional Reliability Standard

Step 1a - A Standard Authorization Request (SAR) to develop, modify or withdraw a FRCC Regional Reliability Standard shall be submitted to the FRCC Standards and Registration staff (via email to FRCCStandard@frcc.com) by any member of the FRCC, or group (i.e. committee, subcommittee, working group or task force) within the FRCC, or any interested party or any entity that is directly and materially affected by reliability of the FRCC Bulk Power System.

Step 1b - The FRCC Standards and Registration staff shall acknowledge receipt of the request within fifteen (15) calendar days of its receipt.

3.4.2 Step 2 –FRCC Regional Reliability Standard Request

The FRCC Standards and Registration staff shall notify the FRCC RECCF of the request.

3.4.3 Step 3 – Posting of FRCC Regional Reliability Standard Request

Step 3a - The SAR will be posted for notification and comment on the FRCC public website for a period of fifteen (15) calendar days.

- For SARs that address the development of a new standard, the SAR will be posted for a fifteen (15) calendar day formal comment period.
- For SARs that are limited to modifications to or withdrawal of existing standards, the SAR will be posted for a fifteen (15) calendar day informal comment period.

The intent of the formal comment periods is to solicit very specific feedback on the SAR and technical justification. A written response to each comment received is required.

Feedback gathered from the informal comment period shall be publicly posted and, while a written response to each individual comment received is not required, a summary response that identifies how the comments were considered is required.

A notice of the posting for comment shall be sent to (1) the Registered Ballot Body Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator.

Step 3b - Following the comment period, the FRCC Standards and Registration staff shall present the SAR, supporting documents, industry comments with resolution to the FRCC RECCF for review.

3.4.4 Step 4 – Acceptance of a FRCC Regional Reliability Standard Request

Step 4 - The FRCC RECCF reviews the SAR, supporting documents, industry comments and resolutions and takes one of the following actions:

- Accept the SAR.
- Remand the SAR back to the requester and FRCC Standards and Registration staff for additional work. The FRCC RECCF will provide a written explanation for the remand.
- Reject the SAR. If the FRCC RECCF rejects a SAR, a written explanation for rejection will be provided to the requester within ten (10) calendar days of the rejection decision.
- Delay action on the SAR pending development of a technical justification for the proposed project.

The review decision will be publically posted.

Step 4a - If accepted, the FRCC RECCF will seek industry volunteers, establish the SDT to further develop the SAR (if necessary), draft the Regional Reliability Standard and to address comments submitted during the posting periods. The FRCC Standards and Registration staff will publicly post a request for fifteen (15) calendar days soliciting industry volunteers to participate on the SDT.

Step 4a.1 - FRCC Standards and Registration staff will present a list of qualified candidates to the FRCC RECCF for potential assignment to the SDT.

Step 4b - If the request is rejected, the FRCC Standards and Registration staff will send notification to the entity making the request.

Step 4c - If the FRCC RECCF is presented with a SAR that proposes developing a new standard but does not have a technical justification upon which the standard can be developed, the FRCC RECCF shall delay action and direct the FRCC Standards and Registration staff to post the SAR for a thirty (30) calendar day comment period solely to collect stakeholder feedback on the scope of technical foundation, if any, needed to support the proposed project. If a technical foundation is determined to be necessary, the FRCC RECCF shall solicit assistance from FRCC's technical committees or other industry experts in providing that foundation before authorizing development of the associated standard.

3.4.5 Step 5 – Drafting and Posting of a FRCC Regional Reliability Standard

Step 5a - The FRCC RECCF will assign a SDT, within sixty (60) calendar days of acceptance of the request, to develop, in a timely manner, a draft FRCC Regional Reliability Standard that will address the accepted request.

Step 5b - The SDT shall develop a project schedule and report progress, to the FRCC RECCF, against that schedule as requested by the FRCC RECCF.

The SDT, shall consider all comments received on the posting of the SAR and shall develop a draft FRCC Regional Reliability Standard and corresponding implementation plan.

The SDT shall develop a Reliability Standard that is within the scope of the associated SAR that includes all required elements as described earlier in this manual with a goal of meeting the quality attributes identified in NERC's *Ten Benchmarks for Excellent Reliability Standards* and criteria for governmental approval. The team shall document its justification for the requirements in its proposed standard by explaining how each meets these criteria.

As the SDT drafts a Reliability Standard, that team is also required to develop an implementation plan to identify any factors for consideration when approving the proposed effective date or dates for the associated standard or standards. A single implementation plan may be used for more than one standard. As a minimum, the implementation plan shall include the following:

- The proposed effective date (the date entities shall be compliant) for the requirements.
- Identification of any new or modified definitions that are proposed for approval with the associated standard.
- Whether there are any prerequisite actions that need to be accomplished before entities are held responsible for compliance with one or more of the requirements.
- Whether approval of the proposed standard will necessitate any conforming changes to any already approved standards – and identification of those standards and requirements.
- The functional entities that will be required to comply with one or more requirements in the proposed standard.

The SDT shall work with FRCC Standards and Registration staff in developing a set of VRFs and VSLs that meet the latest criteria established by the NERC and governmental authorities. The SDT shall document its justification for selecting each VRF and for setting each set of proposed VSLs by explaining how its proposed VRFs and VSLs meet these criteria. FRCC Standards and Registration staff is responsible for ensuring that the VRFs and VSLs proposed for stakeholder review meet these criteria.

Before the SDT has finalized its standard, implementation plan, VRFs and VSLs, the SDT should seek stakeholder feedback on its preliminary draft documents.

The SDT may use a variety of methods to collect stakeholder feedback on preliminary drafts of its documents, including the use of informal comment periods, webinars, industry meetings, workshops, or other mechanisms. Informal comment periods, if used, shall have a minimum duration of fifteen (15) calendar days. Information gathered from informal comment forms shall be publicly posted and, while drafting teams are not required to provide a written response to each individual comment received, drafting teams must post a summary response that identifies how it used comments submitted by stakeholders. The intent is to gather stakeholder feedback on a "working document" before the document reaches the point where it is considered the "final draft."

The FRCC Standards and Registration staff shall conduct a quality review of the new or modified standard, its associated VRFs and VSLs, and implementation plan prior to each posting.

Step 5c - The initial formal comment period, and if necessary subsequent formal comment periods, shall be for at least thirty (30) calendar day duration and shall start after the SDT has posted its consideration of stakeholder comments and any conforming changes to the associated standard.

The intent of the formal comment periods is to solicit very specific feedback on the final draft of the standard, VRFs, VSLs, and implementation plan. If stakeholders disagree with some aspect of the proposed set of products, comments provided should suggest specific language that would make the product acceptable to the stakeholder.

Notice of the posting will go out to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator to seek comments.

Comments shall be submitted (via email) to the FRCC Standards and Registration staff (FRCCStandard@frcc.com). All comments are due by the close of business on the posted due date. If the comment due date falls on a weekend or nationally recognized holiday, the comments shall be due by the close of business on the next regularly scheduled business day.

3.4.6 Step 6 – Standards Drafting Team Review of Comments

The FRCC Standards and Registration staff will forward all comments to the SDT for consideration. All timely comments will be considered.

The SDT shall review the comments received and revise the draft FRCC Regional Reliability Standard and/or implementation plan as needed. The SDT shall develop written responses to each comment received.

All responses to the submitted comments will be documented and posted on the FRCC public website. If needed, a revised draft of the FRCC Regional Reliability Standard shall be posted for another comment period.

Notice of the posting will go out to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator to seek comments.

Based on comments received to the posting, appropriate portions of **Step 5** will be repeated as necessary until the SDT believes the draft FRCC Regional Reliability Standard is ready to submit to the Ballot Pool for approval.

3.4.7 Step 7 –Establishment of Ballot Pool

The FRCC Standards and Registration staff shall establish a Ballot Pool during the first fifteen (15) calendar days of the first thirty (30) calendar day formal comment period. The FRCC Standards and Registration staff shall post the proposed standard, its implementation plan, VRFs, and VSLs and shall send a notice to every entity in the Registered Ballot Body to provide notice that there is a new or revised standard proposed for approval and to solicit participants for the associated ballot pool. One member from each entity of the Registered Ballot Body is eligible to join each Ballot Pool to vote on a new or revised Reliability Standard and its implementation plan. Members who join the Ballot Pool to vote on the new or revised standard and its implementation plan are automatically entered into the ballot pool to participate in the non-binding poll of the associated VRFs and VSLs.

Any member of the Registered Ballot Body may join or withdraw from the ballot pool until the ballot window opens. No Registered Ballot Body member may join or withdraw from the ballot pool once the first ballot starts through the point in time where balloting for that standard action has ended. The FRCC Manager of Standards and Registration may authorize deviations from this rule for extraordinary circumstances such as the death, retirement, or disability of a ballot pool member that would prevent an entity that had a member in the ballot pool from eligibility to cast a vote during the ballot window. Any approved deviation shall be documented and noted to the FRCC RECCF.

3.4.8 Step 8 Initial – Ballot of the new or revised FRCC Regional Reliability Standard and Non-Binding Poll of VRFs and VSLs

The FRCC Standards and Registration staff shall announce the opening of the initial ballot window and the non-binding poll of VRFs and VSLs. The ballot window and non-binding poll window shall both take place during the last ten (10) calendar days of the thirty (30) calendar day formal comment period. This allows all stakeholders the opportunity to comment on the final draft of each proposed standard, even those stakeholders who are not members of the Ballot Pool.

The ballot and non-binding poll shall be conducted electronically. The voting and polling windows shall each be a period of ten (10) calendar days but both shall be extended, if needed, until a quorum is achieved. During a ballot window, FRCC shall not sponsor or facilitate public discussion of the standard action under ballot.
The SDT shall consider every stakeholder comment submitted either in response to a formal comment period or submitted with a ballot that includes a proposal for a specific modification

to the standard or its implementation plan posted for comment and approval. The SDT shall be responsive to all comments by providing a written response and indicating whether the drafting team adopted or rejected any recommendations.

If stakeholders submit comments that indicate a specific improvement to one or more of the VRFs or VSLs and the modification would improve consensus without violating the criteria for setting VRFs and VSLs, then the SDT, working with FRCC Standards and Registration staff, shall consider and respond to each comment, and shall make conforming changes to reflect those comments. There is no requirement to conduct a new non-binding poll of the revised VRFs and VSLs if no changes were made to the associated standard; however, if the requirements are modified and conforming changes are made to the associated VRFs and VSLs, another non-binding poll of the revised VRFs and VSLs shall be conducted.

All comments submitted and the responses to those comments shall be publicly posted.

See Attachment C *Development of and Voting of the Registered Ballot Body* for ballot approval and quorum requirements.

If a stakeholder or balloter proposes a significant revision to the standard during the formal comment period or concurrent initial ballot that will improve the quality, clarity, or enforceability of that standard then the SDT shall make such revisions and post the revised standard (that has been significantly changed from the previous ballot) for another public comment period and an additional ballot.

The SDT shall address comments submitted during additional ballot periods (comments submitted from stakeholders during the open formal comment period and comments submitted with negative ballots) in the same manner as for the Initial Ballot. Once the SDT has a draft standard that has been through an "additional ballot" and the team believes that no additional significant modifications are needed, or the SDT has reached a point where it has made a good faith effort at resolving applicable objections, the standard shall be posted for a Final Ballot.

3.4.9 Step 9 - Final Ballot - of the new or revised FRCC Regional Reliability Standard

In the Final Ballot, members of the ballot pool shall again be presented the proposed standard (that has not been significantly changed from the previous ballot) along with the reasons for negative votes, the responses, and any resolution of the differences. An insignificant revision is a revision that does not change the scope, applicability, or intent of any requirement and includes but is not limited to things such as correcting the numbering of a requirement, correcting the spelling of a word, adding an obviously missing word, or rephrasing a requirement for improved clarity. Where there is a question as to whether a proposed modification is "substantive" the FRCC RECCF shall make the final determination. There is no formal comment period concurrent with the Final Ballot and no obligation for the SDT to respond to any comments submitted during the Final Ballot.

All members of the Ballot Pool shall be permitted to reconsider and change their vote from the prior ballot. Members of the Ballot Pool who did not respond to the prior ballot shall be

permitted to vote in the Final Ballot. In the Final Ballot, votes shall be counted by exception only. Members of the ballot pool for the Final Ballot may indicate a revision to their original vote otherwise their vote shall remain the same as in their prior ballot.

There are no limits to the number of "additional" public comment periods and ballots that can be conducted to result in a standard that is clear and enforceable, and achieves a quorum and sufficient affirmative votes for approval. The FRCC RECCF has the authority to conclude this process or a particular standards action if it becomes obvious that the SDT cannot develop a standard that is within the scope of the associated SAR, is sufficiently clear to be enforceable, and achieves the requisite weighted segment approval percentage.

The FRCC Standards and Registration staff shall post the final outcome of the ballot process. If the standard is approved, the consensus standard shall be posted and presented to the Board of Directors for adoption by the FRCC.

3.4.10 Step 10 – Adoption of FRCC Regional Reliability Standards and Implementation Plans by the FRCC Board of Directors

At a regular or special meeting, the FRCC Board of Directors may consider adoption of the proposed FRCC Regional Reliability Standard and the associated implementation plan that have been approved by the Registered Ballot Pool. A FRCC Regional Reliability Standard and the associated implementation plan submitted for adoption by the FRCC Board of Directors must be posted for notification and comment on the FRCC public website at least ten (10) calendar days prior to action by the FRCC Board of Directors. Notice of the posting will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator. The FRCC Board of Directors shall consider the comments received, the responses provided, and any dissenting opinions. The FRCC Board of Directors shall adopt or reject a FRCC Regional Reliability Standard and the associated implementation plan as submitted, but may not modify the proposed FRCC Regional Reliability Standard. If the FRCC Board of Directors chooses not to adopt a FRCC Regional Reliability Standard, it shall provide its reasons for such decision and the decision will be posted on the FRCC public website. Notice of the posting will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator.

The board shall consider approval of the VRFs and VSLs associated with a Reliability Standard. In making its determination, the board shall consider the following:

- FRCC Standards and Registration staff shall present the results of the non-binding poll conducted and a summary of industry comments received on the final posting of the proposed VRFs and VSLs.
- FRCC Standards and Registration staff shall present a set of recommended VRFs and VSLs that considers the views of the SDT, stakeholder comments received on the draft

VRFs and VSLs during the posting for comment process, the non-binding poll results, appropriate governmental agency rules and directives, and VRF and VSL assignments for other Reliability Standards to ensure consistency and relevance across the entire spectrum of Reliability Standards.

3.4.11 Step 11 – Submission to the ERONERC and FERC

Once the FRCC Regional Reliability Standard and the associated implementation plan are adopted by the FRCC Board of Directors, the FRCC Standards and Registration staff shall submit the FRCC Regional Reliability Standard, the associated implementation plan and all supporting documents to the NERC for approval. Upon approval by the NERC, all documentation shall be submitted by the NERC to FERC for approval. If the NERC or FERC rejects the FRCC Regional Reliability Standard, the FRCC Board of Directors will determine if the standard is to be sent back to the FRCC RECCF to incorporate their comments or to take no further action on the standard. A FRCC Regional Reliability Standard that is adopted by the FRCC Board of Directors, approved by the NERC and FERC, shall become effective on a date designated by FERC.

3.5 Special Procedures

3.5.1 Urgent Action

Under certain conditions, the entity making the request or the FRCC RECCF may designate a proposed or revised FRCC Regional Reliability Standard as requiring urgent action. Urgent action may be appropriate when a delay in implementing a proposed or revised FRCC Regional Reliability Standard will materially impact reliability of the Bulk Power System in the FRCC Region. The FRCC RECCF must use its judgment carefully to ensure an urgent action is truly necessary and not simply an expedient way to change or implement a FRCC Regional Reliability Standard.

The entity making the request, or the FRCC RECCF, will prepare a draft of the proposed FRCC Regional Reliability Standard and submit it to the FRCC Standards and Registration staff for urgent action. The submission must include a justification for the urgent action. FRCC Standards and Registration staff shall immediately without delay initiate the *FRCC Regional Reliability Standards Development Process* by posting the draft as specified in Step 5. The posting shall be a minimum of ten (10) calendar days before the Registered Ballot Body can consider the draft for approval. All comments received during the posting will be considered. Once approved by the Registered Ballot Body, the proposed urgent FRCC Regional Reliability Standard will be sent to the FRCC Board of Directors for adoption.

A FRCC Regional Reliability Standard that is adopted by the FRCC Board of Directors, as an urgent action shall have a termination date specified that shall not exceed one hundred eighty (180) calendar days from the approved date. Should there be a need to make the FRCC Regional Reliability Standard permanent, the replacement FRCC Regional Reliability Standard would be required to go through the full standards development process.

An urgent action FRCC Regional Reliability Standard that expires may be renewed by the FRCC Board of Directors using the urgent action process again, in the event a permanent FRCC Regional Reliability Standard has not been adopted. In determining whether to authorize the extension of an urgent action FRCC Regional Reliability Standard the FRCC Board of Directors will request the FRCC RECCF to provide a recommendation to the Board. The FRCC RECCF shall consider the impact to the reliability of the FRCC Bulk Power System of not continuing the FRCC Regional Reliability Standard and consideration will be given to whether expeditious progress is being made toward a permanent replacement.

The FRCC RECCF shall not request the FRCC Board of Directors to extend an urgent action FRCC Regional Reliability Standard if there is insufficient progress toward adopting a permanent replacement FRCC Regional Standard or if the FRCC RECCF lack confidence that a reasonable completion date is achievable. The intent is to ensure that an urgent action FRCC Regional Reliability Standard does not in effect take on a degree of permanence due to the lack of an expeditious effort to develop a permanent replacement FRCC Regional Reliability Standard. With these principles, there is no pre-determined limit on the number of times an urgent action may be renewed.

Each urgent action FRCC Regional Reliability Standard renewal shall be effective only upon adoption by the FRCC Board of Directors, and approval by NERC and FERC.

3.5.2 Regional Definition Development

NERC maintains a glossary of approved terms, entitled the "Glossary of Terms Used in NERC Reliability Standards." The glossary includes terms that have been through the formal approval process and are used in one or more NERC Reliability Standards. There are two sections to the glossary. The first section includes definitions for terms used in continent-wide standards, and the second section includes definitions for terms used in Regional standards that have been adopted by the NERC Board of Trustees. The *Glossary of Terms* is intended to provide consistency throughout the Reliability Standards.

There are several methods that can be used to add, modify or retire a defined term used in a FRCC Regional Reliability Standard.

- Anyone can use a SAR to submit a request to add, modify, or retire a defined term.
- A drafting team may propose to add, modify, or retire a defined term in conjunction with the work it is already performing.

The following considerations should be made when considering proposals for new or revised definitions:

- Regional Entities have defined terms that have been approved for use in Regional Reliability Standards, and where the drafting team agrees with a term already defined by another Region, the same definition should be adopted if needed to support an FRCC Regional Reliability Standard.

- If a term is used in a Reliability Standard according to its common meaning (as found in a collegiate dictionary), the term shall not be proposed for addition to the *Glossary of Terms Used in NERC Reliability Standards*.
- If a term has already been defined, any proposal to modify or delete that term shall consider all uses of the definition in approved standards, with a goal of determining whether the proposed modification is acceptable, and whether the proposed modification would change the scope or intent of any approved standards.
- When practical, where the North American Energy Standards Board (NAESB) has a definition for a term, the drafting team shall use the same definition to support a NERC standard.

Any definition that is balloted separately from a proposed new or modified standard or from a proposal for retirement of a standard shall be accompanied by an implementation plan.

If a SAR is submitted to the FRCC Standards and Registration staff with a proposal for a new or revised definition, the FRCC RECCF shall consider the urgency of developing the new or revised definition and may direct FRCC Standards and Registration staff to post the SAR immediately, or may defer posting the SAR until a later time based on its priority relative to other projects already underway or already approved for future development. If the SAR identifies a term that is used in a standard already under revision by a drafting team, the FRCC RECCF may direct the drafting team to add the term to the scope of the existing project. Any proposal for a new or revised definition shall be processed in accordance with Section III. *Steps in Developing a FRCC Regional Reliability Standard* of this procedure.

3.5.3 Appeals

Any member of the FRCC, or group within the FRCC, or any entity that is directly and materially affected by reliability of the FRCC Bulk Power System, and who feel they have been or will be adversely affected by any procedural action or inaction related to the development, approval, revision, or withdrawal of a FRCC Regional Reliability Standard shall have the right to appeal. This appeals process applies only to the *FRCC Regional Reliability Standards Process* as defined in this document.

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. The final decisions of any appeal shall be documented in writing and posted on the FRCC public website. Notice of the posting will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator.

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

3.5.3.1 Level 1 Appeal

Level 1 is the required first step in this appeals process. The appellant submits to the FRCC Manager of Standards and Registration a complaint in writing that describes the substantive or procedural action associated with a FRCC Regional Reliability Standard or the *FRCC Regional Reliability Standards Process*. The appellant must describe in the complaint, the actual or potential adverse impact to the appellant. Assisted by any necessary staff and committee resources, the FRCC Manager of Standards and Registration 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 record associated with the FRCC Regional Reliability Standard.

3.5.3.2 Level 2 Appeal

If after the Level 1 Appeal, the appellant remains unsatisfied with the resolution, notification shall be made in writing to the FRCC Manager of Standards and Registration. Within thirty (30) calendar days of receiving the notification, the FRCC Manager of Standards and Registration shall convene a Level 2 Appeals Panel. This panel shall consist of five members appointed by the FRCC Board of Directors. In all cases, Level 2 Appeals Panel members shall have no direct affiliation with the participants in the appeal.

The FRCC Manager of Standards and Registration shall post on the FRCC public website the notice of the Level 2 appeal and other relevant materials. Notice of the posting will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator. At least fifteen (15) calendar days' notice of the meeting of the Level 2 Appeals Panel will be made. In addition to the appellant, any entity that is directly and materially affected by the reliability of the FRCC Bulk Power System, and who is directly and materially affected by the substantive or procedural action referenced in the complaint shall be heard by the panel.

The Level 2 Appeals Panel shall not consider any expansion of the scope of the appeal that was not presented in the Level 1 Appeal. The Level 2 Appeals Panel may in its decision find for the appellant and remand the issue to the FRCC RECCF for resolution with a statement of the issues and facts in regard to which fair and equitable action was not taken. The Level 2 Appeals Panel may find against the appellant with a specific statement of the facts that demonstrate fair and equitable treatment of the appellant and the appellant's objections.

The Level 2 Appeals Panel may not, however, revise, approve, disapprove, or adopt a FRCC Regional Reliability Standard, as these responsibilities remain with the FRCC Board of Directors. The actions of the Level 2 Appeals Panel shall be posted on the

FRCC public website. Notice of the posting will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator.

3.6 Maintenance of the FRCC Regional Reliability Standards and Process

3.6.1 Requests to Revise the FRCC Regional Reliability Standard Development Process

Any member of the FRCC, or group (i.e. committee, subcommittee, working group or task force) within the FRCC, or any entity that is directly and materially affected by the reliability of the FRCC Bulk Power System may submit a written request to modify the *FRCC Regional Reliability Standard Development Process Manual*. The FRCC Standards and Registration staff shall oversee the handling of the request. The FRCC Standards and Registration staff shall prioritize all requests, merge related requests, and respond to each requestor within thirty (30) calendar days.

The FRCC Standards and Registration staff shall post the proposed revisions for a thirty (30) calendar day formal comment period. Based on the degree of consensus for the revisions, the FRCC Standards and Registration staff shall:

a.) Submit the revised process or processes for Ballot Pool approval;
b.) Repeat the posting for additional inputs after making changes based on comments received;
c.) Remand the proposal to the requestor for further work; or
d.) Reject the proposal.

The Registered Ballot Body shall be represented by a Ballot Pool. The ballot procedure shall be the same as that defined for approval of a FRCC Regional Reliability Standard, including the use of subsequent ballots (additional or Final Ballots), as necessary. If the proposed revision is approved by the Ballot Pool, the FRCC Standards and Registration staff shall submit the revised procedure to the FRCC Board of Directors for adoption. The FRCC Standards and Registration staff shall submit to the board a description of the basis for the changes, a summary of the comments received, and any minority views expressed in the comment and ballot process. The proposed revisions shall not be effective until approved by the NERC Board of Trustees and applicable governmental authorities.

3.6.2 Five-Year Review of FRCC Regional Reliability Standards

Each FRCC Regional Reliability Standard developed through *FRCC Regional Reliability Standard Development Process* shall be reviewed at least once every five years from the effective date of the standard.
If a FRCC Regional Reliability Standard is nearing its five-year review and has issues that need resolution, then a FRCC Regional Reliability Standard Development project will be initiated for the complete review and associated revision of that standard that includes

addressing all outstanding governmental directives and all unresolved issues identified by stakeholders. The standard development project will be processed in accordance with Section III. *Steps in Developing a FRCC Regional Reliability Standard* of this procedure.

If a FRCC Regional Reliability Standard is nearing its five-year review and there are no outstanding governmental directives or unresolved stakeholder issues associated with that standard, then a FRCC Regional Reliability Standard Development project will be initiated solely for the "five-year review" of that standard and will be addressed by the following process.

For a project that is focused solely on the five-year review, the FRCC RECCF shall appoint a review team of subject matter experts to review the FRCC Regional Reliability Standard and recommend whether the standard should be reaffirmed, revised, or withdrawn. Each review team shall post its recommendations for a thirty (30) calendar day formal stakeholder comment period and shall provide those stakeholder comments to the FRCC RECCF for consideration.

- If a review team recommends reaffirming a FRCC Regional Reliability Standard, the FRCC RECCF shall submit the reaffirmation to the FRCC Board of Directors for concurrence. Reaffirmation does not require approval by stakeholder ballot.

- If a review team recommends modifying or withdrawing a FRCC Regional Reliability Standard, the team shall develop a SAR with such a proposal and the SAR shall be submitted to the FRCC RECCF for acceptance as a new project. Each existing standard recommended for modification or withdrawal shall remain in effect in accordance with the associated implementation plan until the action to modify or withdraw the standard is approved by its ballot pool, adopted by the FRCC Board of Directors, and approved by applicable governmental authorities.

In the case of reaffirmation of a FRCC Regional Reliability Standard, the standard shall remain in effect pending the results of the next five-year review or until the standard is otherwise modified or withdrawn by a separate action.

3.6.3 Filing of FRCC Regional Standards with Regulatory Agencies

All adopted FRCC Regional Reliability Standards will be filed with the NERC Board of Trustees for adoption and subsequently filed with FERC for approval.

4.0 References

Ten Benchmarks for Excellent Reliability Standards
FRCC Bylaws
NERC Regional Standards Review Procedure
NERC Glossary of Terms Used in Reliability Standards
NERC Regional Reliability Standards Evaluation Procedure

5.0 Attachments

Attachment A: FRCC Regional Reliability Standard Authorization Form

Attachment B: Process Diagram

Attachment C: Development of and Voting of the Registered Ballot Body

6.0 Review and Modification History

Review and Modification Log			
Date	Version Number	Description of Review or Modification	Sections Affected
TBD	1	Revised Procedure/New Template	All
9/25/2007	0	Amended	All
10/24/2006	0	Amended	All
7/25/2006	0	Amended	All
3/2/2006	0	New Process	All

Attachment A

FRCC
Florida Reliability Coordinating Council, Inc.

FLORIDA RELIABILITY COORDINATING COUNCIL, INC.
3000 BAYPORT DRIVE, SUITE 600
TAMPA, FLORIDA 33607-8410
PHONE 813.289.5644 • FAX 813.289.5646
WWW.FRCC.COM

FRCC Regional Reliability Standard Request Form

Email completed form to FRCCStandard@frcc.com

Title of Standard
Request Date

Requestor Information	**TYPE** *(Check a box for each one that applies)*
Name	☐ New Standard
Primary Contact	☐ Revision to existing Standard
Telephone Fax	☐ Withdrawal of existing Standard
Email	☐ Urgent Action

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

Industry Need (Provide at a minimum, a discussion of the reliability-related impact of not developing the new standard, and a technical foundation document (e.g., research paper), when needed, to guide the development of the 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).

FRCC Regional Reliability Standard Request Form (cont.)

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

☐	Reliability Coordinator	Responsible for the real-time operating reliability of it Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its balancing authority and supports system frequency in real time.
☐	Planning Authority	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a one-year plan for the resource adequacy of specific loads within a Planning Coordinator area
☐	Transmission Planner	Develops a one-year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides the transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities
☐	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders.
☐	Distribution Provider	Delivers electrical energy to the end-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation units(s) to provide real and reactive power.

FRCC Regional Reliability Standard Request Form (cont.)

NERC Reliability Principles

Applicable Reliability Principles (Check box for all that apply.)	
☐	1. Interconnected Bulk Electric Systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected Bulk Electric 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 Electric 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 Electric 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 Electric Systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored, and maintained on a wide-area basis.

FRCC Regional Reliability Standard Request Form (cont.)

NERC Market Interface Principles

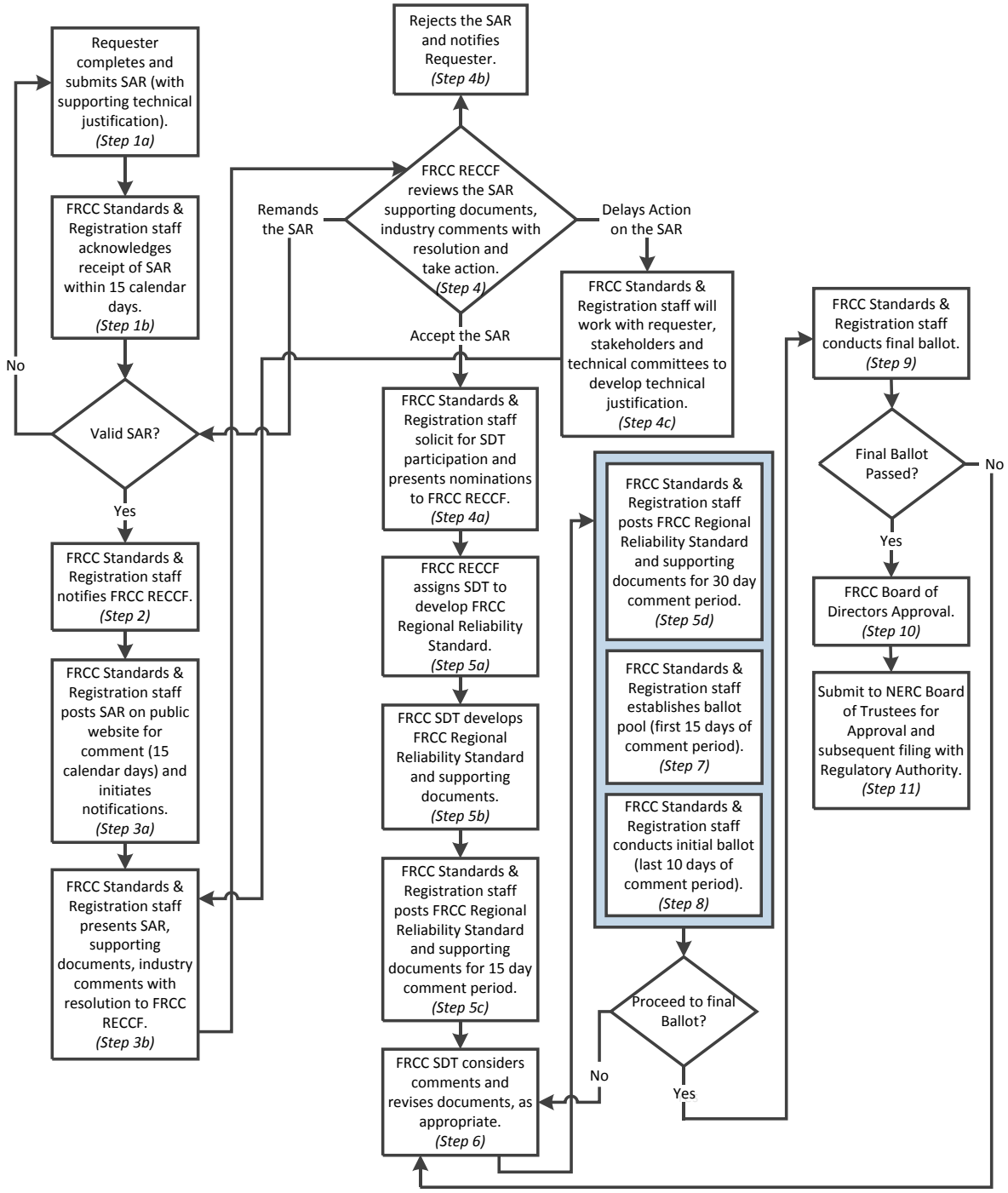
Does the proposed Standard comply with all of the following Market Interface Principles?	
yes or no ☐ ☐	1. A Reliability Standard shall not give any market participant an unfair competitive advantage.
yes or no ☐ ☐	2. A Reliability Standard shall neither mandate nor prohibit any specific market structure.
yes or no ☐ ☐	3. A Reliability Standard shall not preclude market solutions to achieving compliance with that standard.
yes or no ☐ ☐	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.

Related Standards

Standard No.	Explanation

Attachment B

FRCC Regional Reliability Standard Development Process Flowchart



Attachment C

FRCC
Florida Reliability Coordinating Council, Inc.

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Development of and Voting of the Registered Ballot Body

1. Registration Procedures

The Registered Ballot Body comprises all entities[2] and persons that:

- Qualify for one of the FRCC Industry Sectors, and
- Are registered with the FRCC as potential ballot participants in the voting on FRCC Regional Reliability Standards.

All registrations will be done electronically. All entities and persons will self-select to belong to the Registered Ballot Body. The sectors shall be identical to those in Section 1.2 of the *FRCC Bylaws*.

All Registered Ballot Body members will have the ability to vote on a standard. Voting will be done in writing (either email or facsimile) with each Registered Ballot Body member having one vote. The Registered Ballot Body representative will have the right to register and participate in ballot pools to cast their vote on a standard being considered for approval.

2. Sector Qualification Guidelines

The general guidelines are as follows:

- An entity or person may register in the Registered Ballot Body in any Sector in which it qualifies for provided that an entity or person registers as a potential ballot participant in only one (1) Sector.
- Any individual currently employed by an organization that is eligible to join one or more of the other five (5) sectors, shall not be qualified to join as a General Sector Registered Ballot Body member.

[2] An entity and all of its Affiliates (as defined in the FRCC Bylaws) shall be considered one entity for purposes of registering as a potential ballot participant.

3. Ballot Pool Voting

A Ballot Pool will be established to vote on any proposed standards action. Each Registered Ballot Body member choosing to belong to a Ballot Pool will have one individual vote. Two-thirds of the individual votes[3] of the Ballot Pool shall constitute a quorum.

Approval of a FRCC Regional Reliability Standard requires the affirmative vote of a two-thirds majority of the weighted sector votes cast.

The following steps will be used to determine if there are sufficient affirmative votes:

3.1. The number of affirmative votes cast in each sector will be divided by the sum of affirmative and negative votes cast to determine the fractional affirmative vote for each sector. Negative votes without comments and abstentions will not be counted.

3.2. The fractional affirmative vote for a sector will then be multiplied by the Sector Weight Factor to determine the weighted fractional affirmative vote for a sector.

The Sector Weight Factors are:

Suppliers Sector: Weight Factor = 2.5
Non-Investor Owned Utility Wholesale Sector: Weight Factor = 2.0
Load Serving Entity Sector: Weight Factor = 1.0
Generating Load Serving Entity Sector: Weight Factor = 3.0
Investor Owned Utility Sector: Weight Factor = 3.5
General Sector: Weight Factor = 1.0

3.3. The sum of the weighted fractional affirmative votes from all sectors divided by the sum of the weights of the sectors voting will be used to determine if a two-thirds majority has been achieved. A sector will be considered as "voting" if any member of the sector in the Ballot Pool casts either an affirmative or negative vote.

3.4. A FRCC Regional Reliability Standard will be considered "approved" if the sum of the weighted fractional affirmative votes from all sectors divided by the sum of the weights of the voting sectors is two-thirds or greater.

3.5. Each member of the Ballot Pool may vote one of the following positions:

Affirmative
Affirmative, with comment
Negative without comment

[3] Quorum is determined based on the individual votes cast (affirmative, negative, negative without comments and abstentions)

Negative with comments (if possible reasons should include specific wording or actions that would resolve the objection)
Abstain

3.6. Each Ballot Pool member submitting a negative vote with comments shall determine if the response provided by the drafting team satisfies those stated concerns. Each such balloter shall be informed of the appeals process contained within this manual.

3.7. If a standard achieves a quorum and there are no negative votes with comments from the initial ballot, and the overall approval is at least two thirds (weighted by segment) then the results of the Initial Ballot shall stand as final and the draft Reliability Standard and associated implementation plan shall be deemed to be approved by its Ballot Pool.

ATTACHMENT 2:

Amended Florida Reliability Coordinating Council Regional Reliability Standard Development Process Manual – Redline



FRCC REGIONAL RELIABILITY STANDARD DEVELOPMENT PROCESS MANUAL

FRCC-RE-STD-001

Effective Date: Month Day, Year

Version: 1

3000 Bayport Drive, ~~Amended~~ ~~*September 25, 2007*~~



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Regional Reliability www.frcc.com

TITLE	NAME	DATE
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~~Nomination, Modification or Withdrawal of a Regional Standard ..... 7~~

Original Author: Peter Heidrich
Effective Date: MM/DD/YY
Responsible Department: Standards ~~Development Process Roles 7~~and Registration

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Next Planned

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1.0 Purpose

This manual establishes the process for development, revision, withdrawal and approval of ~~FRCC~~Florida Reliability Coordinating Council, Inc. (FRCC) Regional Reliability Standards for the FRCC Region.~~-~~ FRCC Regional Reliability Standards apply to the reliability planning and reliable operation of the Bulk Power System in the FRCC Region. Proposed FRCC Regional Reliability Standards shall be subject to approval by the North American Electric Reliability Corporation (NERC), as the ~~electric reliability organization,~~Electric Reliability Organization (ERO) and by the Federal Energy Regulatory Commission (FERC) before becoming mandatory and enforceable under Section 215 of the Federal Power Act. FRCC Regional Reliability Standards, when approved by FERC, shall be made part of the body of the NERC ~~reliability standards~~Reliability Standards and shall be enforced upon all applicable bulk power system owners, operators and users within the FRCC Region, regardless of membership in the region.

The FRCC Regional Reliability Standards Development Process is based on providing an open and fair process that ensures all interested and affected parties have an opportunity to participate in the development of FRCC Regional Reliability Standards. Any entity (person, organization, company, government agency, individual, etc.) with a direct and material interest in the reliability of the FRCC Bulk Power System has a right to participate by: a) expressing a position and its basis, b) having that position considered, c) voting on and d) having the right to appeal.

2.0 Background

FRCC is responsible for promoting and assuring the reliability of the interconnected Bulk Power System in Peninsular Florida. FRCC carries out its mission through 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.

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, FRCC as a Regional Entity with delegated authority from NERC may propose regional standards to NERC for eventual enforcement within the FRCC region.

NERC Reliability Standards are comprised of both continent-wide and regional standards. The FRCC regional standards apply only to that part of the Eastern Interconnection within the FRCC geographical area.

3.0 FRCC Regional Reliability Standards Development Process

~~1.1~~3.1 FRCC Regional Reliability Standard Principles

FRCC Regional Reliability Standards go beyond, add detail to, or implement the NERC Reliability Standards, or cover matters not addressed in the NERC Reliability Standards. FRCC Regional Reliability Standards shall not be inconsistent with or less stringent than the NERC Reliability Standards.

FRCC Regional Reliability Standards are based on the *NERC's Reliability Principles* and *Market Interface Principles*. Each FRCC Regional Reliability Standard shall enable or support one or more of *NERC's Reliability Principles* and must accommodate competitive electricity markets by being consistent with ~~NERC's~~*NERC's* *Market Interface Principles*.

The FRCC Regional Reliability Standard Development Process defines the fair and open process for development, revision, withdrawal and approval of FRCC Regional Reliability Standards for the FRCC Region and has the following characteristics:

- ~~**Due**~~*Open Participation* – Participation in the FRCC Regional Reliability Standards Development Process ~~– Any interested party, or any entity~~is open to all entities that ~~is~~are directly and materially affected by FRCC Reliability Standards or the reliability of the FRCC Bulk Power System ~~has a right to participate in this process as indicated in this manual.~~

~~**Openness** – Participation is open to any interested party or any entity that is directly~~. There shall be no financial barriers to participation and ~~materially affected by the reliability of the FRCC Bulk Power System. Participation~~ participation shall not be conditional upon membership in ~~the FRCC.~~ any organization, nor unreasonably restricted on the basis of technical qualifications or other such requirements. All FRCC Regional Reliability Standard ~~development~~Development meetings will be ~~open and~~publically noticed on the FRCC website.

Balance – The FRCC Regional Reliability Standard Development Process shall have a balance of interests and shall not be dominated by any two interest categories, individuals, or organizations and no single interest category, individual, or organization shall be able to defeat a matter.

~~II. FRCC Regional Reliability Standard Definition, Characteristics, and Elements~~

Voting – FRCC shall use a voting formula that allocates each industry sector an equal weight in determining the final outcome of any standard action. The FRCC Regional Reliability Standards Development Process shall have a balance of interests. Participants from diverse interest categories shall be encouraged to join the Registered Ballot Body and participate in the balloting process, with a goal of achieving balance between the interest categories. The Registered Ballot Body serves as the consensus body voting to approve each new or proposed Regional Reliability Standard, and/or definition.

Notification of standards development - FRCC shall distribute notices to each member of the Registered Ballot Body, and to each stakeholder who indicates a desire to receive such notices, for each action to create, revise, reaffirm, or withdraw a standard. Notices shall be distributed electronically, with links to the relevant information, and notices shall be posted on FRCC's Standards web page. All notices shall identify a readily available source for further information.

Transparency – The *FRCC Regional Reliability Standards Development Process* shall be transparent to the public.

Consideration of views and objections - Drafting teams shall give prompt consideration to the written views and objections of all participants, providing individualized written responses to those commenting during formal comment periods and those commenting as part of the balloting process. Drafting teams shall make an effort to resolve each objection that is related to the topic under review.

Consensus building - The process shall build and document consensus for each standard, both with regard to the need and justification for the standard and the content of the standard.

Consensus vote - FRCC shall use its voting process to determine if there is sufficient consensus to approve a proposed Reliability Standard, or definition. FRCC shall form a Ballot Pool for each standard action from interested members of its Registered Ballot Body. Approval of any standard action requires:

- A quorum, which is established by at least two thirds of the members of the Ballot Pool submitting a response with an affirmative vote, a negative vote, or an abstention; and
- A two-thirds majority of the weighted segment votes cast shall be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

Timeliness – Development of standards shall be timely and responsive to new and changing priorities for reliability of the FRCC Bulk Power System.

3.2 FRCC Regional Reliability Standard Elements

~~1.1.1~~3.2.1 Definition

A FRCC Regional Reliability Standard defines certain obligations or requirements of all owners, operators and users of the FRCC Bulk Power System regardless of membership in the FRCC. The obligations or requirements must be material to reliability and measurable. ~~Each obligation and requirement shall support one or more of the NERC reliability principles and shall be consistent with all of the NERC reliability and market interface principles.~~A Reliability Standard is defined in the NERC Glossary of Terms used in NERC Reliability Standards (effective July 1, 2016) as:

A requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for Reliable Operation of the Bulk-Power System. The term includes requirements for the operation of existing Bulk-Power System facilities, including cybersecurity protection, and the design of planned additions or

modifications to such facilities to the extent necessary to provide for Reliable Operation of the Bulk-Power System, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.

FRCC Regional Reliability Standards go beyond, add detail to, or implement the NERC ~~reliability standards~~Reliability Standards, or cover matters not addressed in the NERC ~~reliability standards~~Reliability Standards. FRCC Regional Reliability Standards shall not be inconsistent with or less stringent than NERC ~~reliability standards~~Reliability Standards.

3.2.2 Reliability Principles

FRCC Regional Reliability Standards are based on the *NERC Reliability Principles* that define the foundation of reliability for North American Bulk Power Systems. Each FRCC Regional Reliability Standard shall enable or support one or more of the *NERC Reliability Principles*, thereby ensuring that each standard serves a purpose in support of reliability of the FRCC Bulk Power System. Each FRCC Regional Reliability Standard shall also be consistent with all of the *NERC Reliability Principles*, thereby ensuring that no standard undermines reliability through an unintended consequence.

3.2.3 Market Principles

Recognizing that Bulk Power System reliability and electricity markets are inseparable and mutually interdependent, all FRCC Regional Reliability Standards shall be consistent with the *NERC Market Interface Principles*. Consideration of the Market Interface Principles is intended to ensure that FRCC Regional Reliability Standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

~~1.1.2~~3.2.4 Characteristics

A FRCC Regional Reliability Standard shall have the following characteristics:

Material to Reliability - A FRCC Regional Reliability Standard shall be material to the reliability of the FRCC Bulk Power System. If the reliability of the FRCC Bulk Power System could be compromised without a particular standard or by a failure to comply with that standard, then the standard is material to reliability.

Measurable - A FRCC Regional Reliability Standard shall establish technical or performance requirements that can be practically measured.

Relative to NERC Reliability Standards - A FRCC Regional Reliability Standard must go beyond, add detail to, or implement NERC ~~reliability standards~~Reliability Standards, or cover matters not addressed in NERC ~~reliability standards~~Reliability Standards.

3.2.5 Types of Reliability Requirements

Although FRCC Regional Reliability Standards have a common format and process, several types of Reliability Standards requirements may exist, each with a different approach to measurement:

- ~~**Technical standards** related to the provision, maintenance, operation, or state of Bulk Power System will likely contain measures of physical parameters and will often be technical in nature.~~

- ~~**Performance standards** related to the~~ *Performance-based requirements* define a specific reliability objective or outcome that has a direct, observable effect on the reliability of the Bulk Power System, i.e. an effect that can be measured using power system data or trends.

  Risk-based requirements define actions of entities ~~providing for or impacting~~that reduce a stated risk to the reliability of the ~~FRCC~~ Bulk Power System ~~will likely contain measures~~and can be measured by evaluating a particular product or outcome resulting from the required actions.

  Capability-based requirements define capabilities needed to perform reliability functions and can be measured by demonstrating that the capability exists as required.

  The body of FRCC reliability requirements, combined with the NERC reliability requirements, collectively provides a defense-in-depth strategy supporting reliability of the ~~results of such actions, or the nature of the performance of such actions~~FRCC Bulk Power System.

- ~~**Preparedness standards** related to the actions of entities to be prepared for conditions that are unlikely to occur but are critical to reliability will likely contain measures of such preparations or the state of preparedness.~~

~~1.1.3~~3.2.6 Elements of a Reliability Standard

A FRCC Regional Reliability Standard ~~shall consist of the~~ includes many elements designed to work collectively to identify what entities must do to meet their reliability-related obligations as an owner, operator or user of the FRCC Bulk Power System. Elements that are considered mandatory and enforceable are identified ~~in this section of this manual. These~~ below. The elements ~~are intended to apply a systematic discipline in the development and revision~~of a Reliability Standard include the following:

Title: A brief, descriptive phrase identifying the topic of ~~Reliability Standards. The format allows~~ the standard.

Number: A unique identification number assigned in accordance with a published classification system to facilitate tracking and reference to the standards.

Purpose: The reliability outcome achieved through compliance with the requirements of the standard.

Applicability (mandatory and enforceable): Provides clear identification of the functional classes of entities responsible for complying with the standard, noting any specific additions or exceptions.

If not applicable to the entire FRCC, then a clear identification of the portion of the FRCC Bulk Power System to which the standard applies will be made. Any limitation on the applicability of the standard based on electric facility requirements should be described.

Effective Dates (mandatory and enforceable): Identification of when each requirement becomes effective within the jurisdiction of the FRCC.

Requirement (mandatory and enforceable): An explicit statement ~~of the purpose, requirements, measures, and compliance elements~~that identifies the functional entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each requirement shall be a statement for which compliance is mandatory.

Measure: Provides identification of the evidence or types of evidence that may demonstrate compliance with the associated ~~with each Reliability Standard. Supporting documents to aid in~~ requirement. Each requirement shall have at least one measure. Each measure shall clearly refer to the requirement(s) to which it applies.

Evidence Retention: Identification, for each requirement in the standard, of the entity that is responsible for retaining evidence to demonstrate compliance, and the duration for retention of that evidence.

Application Guidelines: Guidelines to support the implementation of ~~a Reliability Standard may be referenced by the~~ the associated standard.

Procedures: Procedures to support implementation of the associated standard.

Time Horizon: The time period related to when a requirement takes place or how much time there may be to mitigate a violation of the associated requirement.

Compliance Enforcement Authority: The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated standard.

Additional Compliance Information: Any other information related to assessing compliance such as the criteria or periodicity for filing specific reports.

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 FRCC Regional Reliability Standard. Each requirement in each Reliability Standard ~~but are not part of the~~ has an associated VRF and a set of VSLs. VRFs and VSLs are developed by the drafting team, working with FRCC Standards and Registration staff, at the same time as the associated Reliability Standard ~~itself~~, but are not part of Reliability Standard. The FRCC Board of Directors is responsible for approving VRFs and VSLs.

~~Performance Elements of a FRCC Regional Reliability Standard~~

~~**Identification Number**~~	~~A unique identification number assigned in accordance with an administrative classification system to facilitate tracking and reference.~~
~~**Title**~~	~~A brief, descriptive phrase identifying the topic of the Reliability Standard.~~
~~**Applicability**~~	~~Clear identification of the functional classes of entities responsible for complying with the standard, noting any specific additions or exceptions.~~ ~~If not applicable to the entire FRCC, then a clear identification of the portion of the bulk power system to which the standard applies. Any limitation on the applicability of the standard based on electric facility requirements should be described.~~
~~**Effective Date and Status**~~	~~The effective date of the Reliability Standard or, the proposed effective date.~~
~~**Purpose**~~	~~The purpose of the Reliability Standard. The purpose shall explicitly state what outcome will be achieved or is expected by this Reliability Standard.~~
~~**Requirement(s)**~~	~~Explicitly stated technical, performance, and preparedness requirements. Each requirement identifies what entity is responsible and what action is to be performed or what outcome is to be achieved. Each statement in the requirements section shall be a statement for which compliance is mandatory. Any additional comments or statements for which compliance is not mandatory, such as~~

	background or explanatory information should be placed in a separate document and referenced.
Risk Factor(s)	The potential reliability significance of each requirement, designated as a High, Medium or Lower Risk Factor in accordance with the criteria listed below: A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the FRCC Bulk Power System, or the ability to effectively monitor and control the FRCC Bulk Power System; or (b) is 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 affect the electrical state or capability of the FRCC Bulk Power System, or the ability to effectively monitor, control, or restore the FRCC Bulk Power System. A Medium Risk Factor requirement (a) is one that, if violated, could directly affect the electrical state or the capability of the FRCC Bulk Power System but is unlikely to lead to FRCC Bulk Power System instability, separation, or cascading failures; or (b) is a requirement in the planning time frame that , if violated, could under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the FRCC Bulk Power System, or the ability to effectively monitor and control the FRCC Bulk Power System but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to FRCC Bulk Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition. A High Risk Factor requirement (a) is one that, if violated, could directly cause or contribute to FRCC Bulk Power System instability, separation, or a cascading sequence of failures, or could place the FRCC Bulk Power System at an unacceptable risk of instability, separation, or cascading failures, or (b) is 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 FRCC Bulk Power System instability, separation, or a cascading sequence of failures, or could place the FRCC Bulk Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Measure(s)	Each requirement shall be addressed by one or more measures. Measures that will be used to assess performance and outcomes for the purpose of determining compliance with the requirements stated above. Each measure identifies to whom the measure applies and the expected level of performance or outcomes required to demonstrate compliance. Each measure shall be tangible, practical, and as objective as is practical. Achieving the measure should be a necessary and sufficient indicator that the requirement was met. Each measure shall clearly refer to the requirement(s) to which it applies.
Compliance Monitoring Process	The compliance elements define: • The specific data or information that is required to measure performance or outcomes. • The entity that is responsible to provide the data or information for measuring performance or outcomes. • The process that will be used to evaluate data or information for the purpose of assessing performance or outcomes. • The entity that is responsible for evaluating data or information to assess performance or outcomes. • The time period in which performance or outcomes is measured, evaluated, and then reset. • Measurement data retention requirements and assignment of responsibility for data archiving.
Violation Severity Levels	Defines the degree to which compliance with a requirement was not achieved. The violation severity levels, are part of the standard and are approved with the standard.

III. Roles in the FRCC Regional Reliability Standard Development Process

Violation Risk Factors (VRFs): 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): 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.

~~1.1.4~~3.2.7 Nomination, Modification, or Withdrawal of ~~A~~a Regional Standard

Any member of the FRCC, or group (i.e. committee, subcommittee, working group or task force) within the FRCC, shall be allowed to request that a FRCC Regional Reliability Standard be developed, modified, or withdrawn. Additionally, any interested party or any entity that is directly and materially affected by the reliability of the FRCC Bulk Power System shall be allowed to request that a FRCC Regional Reliability Standard be developed, modified, or withdrawn.

A FRCC Standard Authorization Request (SAR) is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified standards or the benefit of retiring one or more approved standards. Any entity or individual may propose the development of a new or modified standard, or may propose the retirement of a standard, by submitting a completed SAR to the FRCC Standards and Registration staff at FRCCStandard@frcc.com.

Each SAR that proposes a "new" standard, should be accompanied with a technical justification that includes, as a minimum, a discussion of the reliability-related impact of not developing the new standard, and a technical foundation document (e.g., research paper), when needed, to guide the development of the standard.

~~1.2~~3.3 Responsibilities and Roles in the FRCC Regional Reliability Standard Development Process ~~Roles~~

3.3.1 FRCC Board of Directors –

The FRCC Board of Directors (BOD) shall consider for adoption ~~as~~ FRCC Regional Reliability ~~Standards, those~~ Standards, definitions, and associated implementation plans that have been developed and approved by the processes identified in this ~~process.~~ manual. In addition, the board shall consider for approval, VRFs and VSLs associated with each approved standard. Once the Board adopts a FRCC Regional Reliability Standard, ~~such Standard shall be submitted to~~ or definition, or once the Board approves VRFs or VSLs, the Board shall direct FRCC Standards and Registration staff to file the document(s) with NERC for approval~~. When approved by NERC, it will be submitted to FERC for approval~~ with the applicable regulatory authorities.

3.3.2 Registered Ballot Body ~~(RBB) –~~

The ~~registered ballot body~~Registered Ballot Body votes to approve FRCC Regional Reliability Standards~~.~~, definitions, and associated implementation plans. The ~~RBB~~Registered Ballot Body comprises all entities ~~or persons~~and individuals that qualify for one of the FRCC Industry Sectors as defined in Section 1.2 of the FRCC Bylaws, and are registered with FRCC as potential ballot participants in the voting on standards. FRCC membership is not a requirement to participate in the development of, and voting on, FRCC Regional Reliability

Standards. Any entity or ~~person~~individual that has a material interest in the reliability of the FRCC Bulk Power System shall be allowed to register as potential ballot participants in the ~~RBB. (See Appendix C)~~Registered Ballot Body. (See Attachment C) Each member of the Registered Ballot Body is eligible to join the Ballot Pool for each standard action.

3.3.3 Ballot Pool ~~(BP)~~

Each standard action has its own ~~BP~~Ballot Pool formed of interested members of the ~~RBB.~~ Registered Ballot Body. The ~~BP~~Ballot Pool comprises those members of the ~~RBB~~Registered Ballot Body that respond to a pre-ballot survey participation request for that particular standard ~~that indicates their desire to participate in the ballot of that standard.~~ action. The ~~BP~~Ballot Pool will vote to approve each standard action. The Ballot Pool remains in place until all balloting related to that standard action is complete.

FRCC Regional ~~Reliability Standard.~~

3.3.4 ~~FRCC Operating~~Entity Committee ~~(OC)~~ and ~~FRCC Planning Committee (PC)~~ ~~The FRCC OC and the FRCC PC (both of which are~~ Compliance Forum (RECCF)

The FRCC RECCF, a balanced stakeholder ~~committees, see Appendix C) shall have the primary responsibility~~committee, is responsible for managing the standards processes for the development~~, modification or withdrawal of FRCC~~ of standards, VRFs, VSLs, and definitions in accordance with this manual. The responsibilities of the FRCC RECCF are defined in detail in the committee scope document.

Per Section 3.4 of this manual, the FRCC RECCF has the right to remand work to a drafting team, to reject the work of a drafting team, or to accept the work of a drafting team. The FRCC RECCF may direct a drafting team to revise its work to follow the processes in this manual or to meet the criteria for the NERC's *Benchmarks for Reliability Standards*, or to meet the criteria for governmental approval, however the FRCC RECCF shall not direct a drafting team to change the technical content of a draft standard. The FRCC RECCF shall meet at regularly scheduled intervals (either in person, or by other means). FRCC RECCF meetings where topics related to the Standards Development Process are being discussed or acted on will be publically posted on the FRCC website.

3.3.5 FRCC Standards and Registration Staff

The FRCC Standards and Registration staff, led by the Manager of Standards and Registration, is responsible for administering FRCC's Reliability Standards Processes in accordance with this manual and adhering to the requirements identified in the *NERC Regional Reliability Standards~~.~~ Evaluation Procedure*. The FRCC Standards and Registration staff provides support to the FRCC RECCF in managing the standards processes and supporting the work of all drafting teams. The FRCC Standards and Registration staff work to ensure the integrity of the standards processes and consistency of quality and completeness of the Reliability Standards. The FRCC Standards and Registration staff facilitates all steps in the development of standards, definitions, and associated

implementation plans. The FRCC Standards and Registration staff work with drafting teams in developing VRFs and VSLs for each standard.

The FRCC Standards and Registration staff shall coordinate a quality review of the "final draft" of the Reliability Standard, its implementation plan, and VRFs and VSLs to assess whether the documents are within the scope of the associated SAR, whether the standard is clear and enforceable as written, and whether the standard meets the criteria specified in the NERC and FERC guidelines. This review shall normally be completed within thirty (30) calendar days[1] of receipt of the final version of the documents from the Standard Drafting Team (SDT). The detailed results of this review shall be provided to the SDT for consideration. The SDT shall consider the results of the quality review, decide upon appropriate changes, and recommend to the FRCC RECCF whether the documents are ready for formal posting and balloting.

If the FRCC RECCF agrees that the proposed Reliability Standard, implementation plan, and VRFs and VSLs pass this review, the FRCC RECCF shall authorize posting for a formal comment period, ballot (for the standard and implementation plan), and non-binding poll (for VRFs and VSLs) as soon as the work flow will accommodate.

If the FRCC RECCF finds that any of the documents do not meet the specified criteria, the FRCC RECCF shall remand the documents to the SDT for additional work.

If ~~**FRCC Standards Process Manager** – The FRCC Regional Reliability Standard Development Process shall be administered by the FRCC Standards Process Manager. The FRCC Standards Process Manager will ensure the integrity of the process and the consistency of quality and completeness of the FRCC Regional Reliability Standards. The FRCC Standards Process Manager will facilitate all steps in this process, and will coordinate with NERC to ensure required information is posted on both NERC and FRCC websites.~~

~~**Standard Drafting Team –** A team of technical experts, such as FRCC~~ the standard is outside the scope of the associated SAR, the SDT shall be directed to either revise the standard so that it is within the approved scope, or submit a request to expand the scope of the approved SAR. If the standard is not clear and enforceable as written, or if the standard or its VRFs and/or VSLs do not meet the specified criteria, the standard shall be returned to the SDT with specific identification of any requirement that is deemed to be unclear or unenforceable as written.

The FRCC Standards and Registration staff is responsible for presenting standards, and definitions to the FRCC Board of Directors for adoption. When presenting standards-related documents to the FRCC Board of Directors for adoption or approval, the FRCC standards

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

and Registration staff shall report the results of the associated stakeholder ballot, including identification of any unresolved minority stakeholder issues.

3.3.6 Drafting Teams

The FRCC RECCF shall appoint industry subject matter experts to drafting teams to work with stakeholders in developing and refining SARs, standards, VRFs, VSLs and definitions.

Each drafting team consists of a group of technical experts that work cooperatively with the support of the FRCC Standards and Registration staff. The technical experts provide subject matter expertise and guide the development of the technical aspects of the standard. The technical experts maintain authority over the technical details of the standard. Each drafting team appointed to develop a standard is responsible for following the processes identified in this manual from the inception of the assigned project through the final acceptance of that project by applicable governmental authorities.

Collectively, each drafting team will:

- Draft proposed language for the Reliability Standards, definitions, and associated implementation plans.
- Solicit, consider, and respond to comments related to the specific standards development project.
- Participate in industry forums to help build consensus on the draft Reliability Standards, definitions, and associated implementation plans.
- Assist in developing the documentation used to obtain approval and subsequent filing of the Reliability Standards, definitions and associated implementation plans.

The FRCC Standards and Registration staff shall provide a member to support the team with technical writing expertise and shall provide administrative support to the team, guiding the team through the steps in completing its project. The individuals provided by the FRCC Standards and Registration staff serve as advisors to the drafting team and do not have voting rights. The FRCC RECCF may also supplement the membership of a standard drafting team at any time to ensure the necessary competencies and diversity of views are maintained throughout the standard development effort. All drafting teams report to the FRCC RECCF.

3.3.7 Governmental Authorities

The Federal Energy Regulatory Commission (FERC) in the United States of America has the authority to approve each new, revised or withdrawn Reliability Standard, definition, VRF, and VSL following adoption or approval by the NERC Board of Trustees.

~~1.2.1~~3.3.8 FRCC Committees, Subcommittees, Working Groups, ~~Task Forces, or the FRCC Staff, will be appointed by the FRCC OC and/or PC, that will:~~and Task Forces

- ~~Develop the details of the FRCC Regional Reliability Standard,~~

- ~~Consider and respond to industry comments,~~
- ~~Participate in forums to help build consensus on draft FRCC Regional Reliability Standards,~~
- ~~Assist in the implementation of approved FRCC Regional Reliability Standards,~~
- ~~Provide technical oversight in response to changing industry conditions,~~
- ~~Assist in the identification of the need for new FRCC Regional Reliability Standards.~~

FRCC's technical committees, subcommittees, working groups, and task forces may provide technical research and analysis used to justify the development of new standards and may provide guidance, when requested by the FRCC RECCF, in overseeing field tests or collection and analysis of data. The technical committees, subcommittees, working groups, and task forces may provide feedback to drafting teams during both informal and formal comment periods.

The technical committees, subcommittees, working groups, and task forces share their observations regarding the need for new or modified standards or requirements with the FRCC Standards and Registration staff for use in identifying the need for new standards projects.

3.3.9 FRCC Compliance Staff –

The FRCC ~~compliance~~Compliance staff ~~provides~~provide input and comments during the standard development process to ensure the requirements are not ambiguous, that measures ~~will be~~are clear and effective and that the compliance elements of a standard can be practically implemented.

IV. Steps in Developing a FRCC Regional Reliability Standard

3.4 Process for Developing an FRCC Regional Reliability Standard

1.2.23.4.1 Step 1 – Request a new FRCC Regional Reliability Standard or modification to, or withdrawal of an existing FRCC Regional Reliability Standard

A request**Step 1a** - A Standard Authorization Request (SAR) to develop, modify or withdraw a FRCC Regional Reliability Standard shall be submitted to the FRCC Standards Process Managerand Registration staff (via email to FRCCStandard@frcc.com)FRCCStandard@frcc.com) by any member of the FRCC, or group (i.e. committee, subcommittee, working group or task force) within the FRCC, or any interested party or any entity that is directly and materially affected by reliability of the FRCC Bulk Power System. The FRCC Standards Process Manager will acknowledge receipt of the request within fifteen (15) calendar days of its receipt.

Step 1b - The FRCC Standards and Registration staff shall acknowledge receipt of the request within fifteen (15) calendar days of its receipt.

1.2.33.4.2 Step 2 – Assignment of FRCC Regional Reliability Standard Request

The FRCC Standards Process Manager will assignand Registration staff shall notify the FRCC RECCF of the request to the FRCC OC, the FRCC PC, or both as appropriate.

1.2.43.4.3 Step 3 – Posting of FRCC Regional Reliability Standard Request

The request for standard development, modification or withdrawal**Step 3a** - The SAR will be posted for notification and comment on the FRCC public website for a period of fifteen (15) calendar days, and will be reviewed by the FRCC OC and/or PC. A notice of the posting for comment will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator to seek input on the proposed request..

- For SARs that address the development of a new standard, the SAR will be posted for a fifteen (15) calendar day formal comment period.
- For SARs that are limited to modifications to or withdrawal of existing standards, the SAR will be posted for a fifteen (15) calendar day informal comment period.

The intent of the formal comment periods is to solicit very specific feedback on the SAR and technical justification. A written response to each comment received is required.

Feedback gathered from the informal comment period shall be publicly posted and, while a written response to each individual comment received is not required, a summary response that identifies how the comments were considered is required.

A notice of the posting for comment shall be sent to (1) the Registered Ballot Body Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator.

Step 3b - Following the comment period, the FRCC Standards and Registration staff shall present the SAR, supporting documents, industry comments with resolution to the FRCC RECCF for review.

~~1.2.5~~3.4.4 Step 4 – Acceptance of a FRCC Regional Reliability Standard Request

~~The FRCC OC and/or the PC will review the request and any comments submitted to determine if the request received will be accepted or rejected within sixty (60) days of its submission.~~ **Step 4 -** The FRCC RECCF reviews the SAR, supporting documents, industry comments and resolutions and takes one of the following actions:

- Accept the SAR.
- Remand the SAR back to the requester and FRCC Standards and Registration staff for additional work. The FRCC RECCF will provide a written explanation for the remand.
- Reject the SAR. If the FRCC RECCF rejects a SAR, a written explanation for rejection will be provided to the requester within ten (10) calendar days of the rejection decision.
- Delay action on the SAR pending development of a technical justification for the proposed project.

The review decision will be publically posted.

Step ~~and, if~~**4a -** If accepted, the ~~OC and/or the PC~~FRCC RECCF will ~~assign and direct a Standard Drafting Team~~seek industry volunteers, establish the SDT to further develop the SAR (if necessary), draft the Regional Reliability Standard and to address comments submitted during the posting periods. The FRCC Standards and Registration staff will publicly post a request for fifteen (15) calendar days soliciting industry volunteers to participate on the SDT.

Step 4a.1 - FRCC Standards and Registration staff will present a list of qualified candidates to the FRCC RECCF for potential assignment to the SDT.

Step ~~.~~ **4b -** If the request is rejected, the FRCC Standards ~~Process Manager~~and Registration staff will send notification to the entity making the request.

Step ~~and to all entities that received the notice~~ **4c** - If the FRCC RECCF is presented with a SAR that proposes developing a new standard but does not have a technical justification upon

which the standard can be developed, the FRCC RECCF shall delay action and direct the FRCC Standards and Registration staff to post the SAR for a thirty (30) calendar day comment period solely to collect stakeholder feedback on the scope of technical foundation, if any, needed to support the proposed project. If a technical foundation is determined to be necessary, the FRCC RECCF shall solicit assistance from FRCC's technical committees or other industry experts in ~~Step 3 above~~providing that foundation before authorizing development of the associated standard.

~~1.2.6~~3.4.5 Step 5 – Drafting and Posting of a FRCC Regional Reliability Standard

Step 5a - The FRCC ~~OC and/or PC~~RECCF will assign a ~~Standard Drafting Team~~SDT, within sixty (60) calendar days of acceptance of the request, to develop, in a timely manner, a draft FRCC Regional Reliability Standard that will address the accepted request. ~~The FRCC OC and/or PC may provide a timeframe that is desired for completion of the standard development.~~

~~Under the direction of~~ **Step 5b** - The SDT shall develop a project schedule and report progress, to the FRCC ~~OC and/or PC, the Standard Drafting Team, will~~ RECCF, against that schedule as requested by the FRCC RECCF.

The SDT, shall consider all comments received on the posting of the ~~standard request~~SAR and ~~will~~shall develop a draft FRCC Regional Reliability Standard and corresponding implementation plan.

The SDT shall develop a Reliability Standard that is within the scope of the associated SAR that includes all required elements as described earlier in this manual with a goal of meeting the quality attributes identified in NERC's *Ten Benchmarks for Excellent Reliability Standards* and criteria for governmental approval. The team shall document its justification for the requirements in its proposed standard by explaining how each meets these criteria.

As ~~The draft FRCC Regional~~the SDT drafts a Reliability Standard, that team is also required to develop an implementation plan ~~and any supporting~~ to identify any factors for consideration when approving the proposed effective date or dates for the associated standard or standards. A single implementation plan may be used for more than one standard. As a minimum, the implementation plan shall include the following:

- The proposed effective date (the date entities shall be compliant) for the requirements.
- Identification of any new or modified definitions that are proposed for approval with the associated standard.
- Whether there are any prerequisite actions that need to be accomplished before entities are held responsible for compliance with one or more of the requirements.
- Whether approval of the proposed standard will necessitate any conforming changes to any already approved standards – and identification of those standards and requirements.
- The functional entities that will be required to comply with one or more requirements in the proposed standard.

The SDT shall work with FRCC Standards and Registration staff in developing a set of VRFs and VSLs that meet the latest criteria established by the NERC and governmental authorities. The SDT shall document its justification for selecting each VRF and for setting each set of proposed VSLs by explaining how its proposed VRFs and VSLs meet these criteria. FRCC Standards and Registration staff is responsible for ensuring that the VRFs and VSLs proposed for stakeholder review meet these criteria.

Before the SDT has finalized its standard, implementation plan, VRFs and VSLs, the SDT should seek stakeholder feedback on its preliminary draft documents ~~shall be posted for comments on the FRCC public website for a period~~.

The SDT may use a variety of methods to collect stakeholder feedback on preliminary drafts of its documents, including the use of informal comment periods, webinars, industry meetings, workshops, or other mechanisms. Informal comment periods, if used, shall have a minimum duration of fifteen (15) calendar days~~, or such longer period as determined by the~~ . Information gathered from informal comment forms shall be publicly posted and, while drafting ~~team or as directed by the FRCC OC and/or the PC. Notice of the posting will go out to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and~~ teams are not required to provide a written response to each individual comment received, drafting teams must post a summary response that identifies how it used comments submitted by stakeholders. The intent is to gather stakeholder feedback on a "working document" before the document reaches the point where it is considered the "final draft."

The FRCC Standards and Registration staff shall conduct a quality review of the new or modified standard, its associated VRFs and VSLs, and implementation plan prior to each posting.

Step ~~groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator to seek~~ **5c** - The initial formal comment period, and if necessary subsequent formal comment periods, shall be for at least thirty (30) calendar day duration and shall start after the SDT has posted its consideration of stakeholder comments~~.~~ and any conforming changes to the associated standard.

The intent of the formal comment periods is to solicit very specific feedback on the final draft of the standard, VRFs, VSLs, and implementation plan. If stakeholders disagree with some aspect of the proposed set of products, comments provided should suggest specific language that would make the product acceptable to the stakeholder.

Notice of the posting will go out to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator to seek comments.

Comments shall be submitted (via email) to the FRCC Standards ~~Process Manager (FRCCStandard@frcc.com).~~ and Registration staff (FRCCStandard@frcc.com). All comments are due by the close of business on the ~~15th calendar day of posting, or such~~ 20

~~later~~posted due date ~~as determined by the drafting team or as directed by the FRCC OC and/or PC.~~ . If the comment due date falls on a weekend or nationally recognized holiday, the comments shall be due by the close of business on the next regularly scheduled business day.

~~1.2.7~~3.4.6 Step 6 – Standards Drafting Team Review of Comments

~~All comments should be submitted electronically to the~~ The FRCC Standards ~~Process Manager who~~and Registration staff will forward all comments to the ~~Standard Drafting Team~~SDT for consideration. All timely comments will be considered.

~~Under the direction given by the FRCC OC and/or the PC, the Standard Drafting Team will~~The SDT shall review the comments received and revise the draft FRCC Regional Reliability Standard and/or implementation plan as needed. The ~~Standard Drafting Team will~~SDT shall develop written responses to each comment received.

All responses to the submitted comments will be documented and posted on the FRCC public website. If needed, a ~~second~~revised draft of the FRCC Regional Reliability Standard ~~will~~shall be posted for another comment period. ~~Such comment period shall be fifteen (15) calendar days, or such longer period as determined by the drafting team or as directed by the FRCC OC and/or PC.~~
Notice of the posting will go out to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator to seek comments.

~~Notice of the posting will go out to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator to seek comments.~~

Based on comments received to the posting, appropriate portions of **Step** ~~6~~5 will be repeated as necessary until the ~~Standards Drafting Team~~SDT believes the draft FRCC Regional Reliability Standard is ready to submit to the Ballot Pool for approval.

~~1.2.8~~3.4.7 Step 7 –Establishment of Ballot Pool

The FRCC Standards and Registration staff shall establish a Ballot Pool during the first fifteen (15) calendar days of the first thirty (30) calendar day formal comment period. The FRCC Standards and Registration staff shall post the proposed standard, its implementation plan, VRFs, and VSLs and shall send a notice to every entity in the Registered Ballot Body to provide notice that there is a new or revised standard proposed for approval and to solicit participants for the associated ballot pool. One member from each entity of the Registered Ballot Body is eligible to join each Ballot Pool to vote on a new or revised Reliability Standard and its implementation plan. Members who join the Ballot Pool to vote on the new or revised standard and its implementation plan are automatically entered into the ballot pool to participate in the non-binding poll of the associated VRFs and VSLs.

Any member of the ~~The Standard Drafting Team shall submit the final draft of the proposed FRCC Regional Reliability Standard, along with any minority opinions, and all comments and written responses received during the posting(s), to the FRCC Standards Process Manager. The FRCC Standards Process Manager shall establish a Ballot Pool for standard action at least fifteen (15) calendar days prior to the start of a ballot. A pre-ballot survey will be sent to each entity of the RBB to determine their desire to be placed in the Ballot Pool. Once the ballot period opens, the Ballot Pool will be closed and changes to the Ballot Pool participation will not be allowed.~~

Registered Ballot Body may join or withdraw from the ballot pool until the ballot window opens. No Registered Ballot Body member may join or withdraw from the ballot pool once the first ballot starts through the point in time where balloting for that standard action has ended. The FRCC Manager of Standards and Registration may authorize deviations from this rule for extraordinary circumstances such as the death, retirement, or disability of a ballot pool member that would prevent an entity that had a member in the ballot pool from eligibility to cast a vote during the ballot window. Any approved deviation shall be documented and noted to the FRCC RECCF.

~~1.2.9~~3.4.8 Step 8 Initial – Ballot of the new or revised FRCC Regional Reliability Standard and Non-Binding Poll of VRFs and VSLs

The FRCC Standards ~~Process Manager will post the final draft of the standard on the FRCC website at least fifteen (15) calendar days before a~~ and Registration staff shall announce the opening of the initial ballot ~~can begin. The Ballot Pool shall have a minimum~~window and the non-binding poll of VRFs and VSLs. The ballot window and non-binding poll window shall both take place during the last ten (10) calendar days of the thirty (30) calendar day formal comment period. This allows all stakeholders the opportunity to comment on the final draft of each proposed standard, even those stakeholders who are not members of the Ballot Pool.

The ballot and non-binding poll shall be conducted electronically. The voting and polling windows shall each be a period of ten (10) calendar days ~~to vote on a standard. The Ballot Pool may vote to approve~~but both shall be extended, if needed, until a quorum is achieved. During a ballot window, FRCC shall not sponsor or ~~not approve the~~ facilitate public discussion of the standard action under ballot.
The SDT shall consider every stakeholder comment submitted either in response to a formal comment period or submitted with a ballot that includes a proposal for a specific modification to the standard~~. If approved, the FRCC Standards Process Manager will submit the FRCC Regional Reliability Standard, proposed~~ or its implementation plan~~, and any supporting documents to the FRCC Board of Directors for adoption~~ posted for comment and approval. The SDT shall be responsive to all comments by providing a written response and indicating whether the drafting team adopted or rejected any recommendations.

If stakeholders submit comments that indicate a specific improvement to one or more of the VRFs or VSLs and the modification would improve consensus without violating the criteria for setting VRFs and VSLs, then the SDT, working with FRCC Standards and Registration

staff, shall consider and respond to each comment, and shall make conforming changes to reflect those comments. There is no requirement to conduct a new non-binding poll of the revised VRFs and VSLs if no changes were made to the associated standard; however, if the requirements are modified and conforming changes are made to the associated VRFs and VSLs, another non-binding poll of the revised VRFs and VSLs shall be conducted.

All comments submitted and the responses to those comments shall be publicly posted.

See Attachment C *Development of and Voting of the Registered Ballot Body* for ballot approval and quorum requirements.

If a stakeholder or balloter proposes a significant revision to the standard during the formal comment period or concurrent initial ballot that will improve the quality, clarity, or enforceability of that standard then the SDT shall make such revisions and post the revised standard (that has been significantly changed from the previous ballot) for another public comment period and an additional ballot.

The SDT shall address comments submitted during additional ballot periods (comments submitted from stakeholders during the open formal comment period and comments submitted with negative ballots) in the same manner as for the Initial Ballot. Once the SDT has a draft standard that has been through an "additional ballot" and the team believes that no additional significant modifications are needed, or the SDT has reached a point where it has made a good faith effort at resolving applicable objections, the standard shall be posted for a Final Ballot.

3.4.9 Step 9 - Final Ballot - of the new or revised FRCC Regional Reliability Standard

In the Final Ballot, members of the ballot pool shall again be presented the proposed standard (that has not been significantly changed from the previous ballot) along with the reasons for negative votes, the responses, and any resolution of the differences. An insignificant revision is a revision that does not change the scope, applicability, or intent of any requirement and includes but is not limited to things such as correcting the numbering of a requirement, correcting the spelling of a word, adding an obviously missing word, or rephrasing a requirement for improved clarity. Where there is a question as to whether a proposed modification is "substantive" the FRCC RECCF shall make the final determination. There is no formal comment period concurrent with the Final Ballot and no obligation for the SDT to respond to any comments submitted during the Final Ballot.

All members of the Ballot Pool shall be permitted to reconsider and change their vote from the prior ballot. Members of the Ballot Pool who did not respond to the prior ballot shall be permitted to vote in the Final Ballot. In the Final Ballot, votes shall be counted by exception only. Members of the ballot pool for the Final Ballot may indicate a revision to their original vote otherwise their vote shall remain the same as in their prior ballot.

There are no limits to the number of "additional" public comment periods and ballots that can be conducted to result in a standard that is clear and enforceable, and achieves a quorum and sufficient affirmative votes for approval. The FRCC RECCF has the authority to conclude this

process or a particular standards action if it becomes obvious that the SDT cannot develop a standard that is within the scope of the associated SAR, is sufficiently clear to be enforceable, and achieves the requisite weighted segment approval percentage.

The FRCC Standards and Registration staff shall post the final outcome of the ballot process. If the standard is approved, the consensus standard shall be posted and presented to the Board of Directors for adoption by the FRCC.

Step 10~~If approval by the Ballot Pool is not obtained, the PC and/or OC will determine if the draft standard is to be sent back to the standard drafting team to repeat step 6 to incorporate any comments, or to take no further action .~~

~~If no further action is taken, the reason for such will be posted on the FRCC public website. A notice of the posting will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator.~~

~~1.2.10~~3.4.10 ~~Step 9~~ – Adoption of FRCC Regional Reliability Standards and Implementation Plans by the FRCC Board of Directors

At a regular or special meeting, the FRCC Board of Directors may consider adoption of the proposed FRCC Regional Reliability Standard and the associated implementation plan that ~~has~~have been approved by the ~~RBB~~Registered Ballot Pool. A FRCC Regional Reliability Standard and the associated implementation plan submitted for adoption by the FRCC Board of Directors must be posted for notification and comment on the FRCC public website at least ten (10) calendar days prior to action by the FRCC Board of Directors. Notice of the posting will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator. The FRCC Board of Directors shall consider the comments received, the responses provided, and any dissenting opinions. The FRCC Board of Directors shall adopt or reject a FRCC Regional Reliability Standard and the associated implementation plan as submitted, but may not modify the proposed FRCC Regional Reliability Standard. If the FRCC Board of Directors chooses not to adopt a FRCC Regional Reliability Standard, it shall provide its reasons for ~~not doing so~~such decision and the decision will be posted on the FRCC public website. Notice of the posting will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator.

~~If the FRCC Board of Directors chooses not to adopt the proposed FRCC Regional~~The board shall consider approval of the VRFs and VSLs associated with a Reliability Standard~~,~~. In making its determination, the board shall consider the ~~reason for such decision will be posted~~following:

- FRCC Standards and Registration staff shall present the results of the non-binding poll conducted and a summary of industry comments received on the ~~FRCC public website.~~

~~Notice of the~~ final posting ~~will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3)~~of the proposed VRFs and VSLs.

- FRCC Standards and Registration staff shall present a set of recommended VRFs and VSLs that considers the ~~Florida Public Service Commission, and (4)~~views of the ~~SERC Southern Sub-Region~~SDT, stakeholder comments received on the draft VRFs and VSLs during the posting for comment process, the non-binding poll results, appropriate governmental agency rules and directives, and VRF and VSL assignments for other Reliability ~~Coordinator.~~ Standards to ensure consistency and relevance across the entire spectrum of Reliability Standards.

~~1.2.11~~3.4.11 Step ~~10~~11 – Submission to ~~NERC~~the ERONERC and FERC

Once the FRCC Regional Reliability Standard ~~is~~and the associated implementation plan are adopted by the FRCC Board of Directors, the FRCC ~~Standard Process Manager~~Standards and Registration staff shall submit the FRCC Regional Reliability Standard ~~to~~, the associated implementation plan and all supporting documents to the NERC for approval. Upon approval by the NERC ~~for approval. When approved by NERC, it~~, all documentation shall be submitted by the NERC to FERC for approval. If the NERC or FERC rejects the FRCC Regional Reliability Standard, the FRCC Board of Directors will determine if the standard is to be sent back to the ~~OC and/or PC~~FRCC RECCF to incorporate their comments or to take no further action on the standard. A FRCC Regional Reliability Standard that is adopted by the FRCC Board of Directors, approved by the NERC and FERC, shall become effective on a date designated by FERC.

~~1.3~~3.5 ~~V.~~ Special Procedures

~~1.3.1~~3.5.1 Urgent Action

Under certain conditions, the entity making the request or the FRCC ~~OC and/or the PC~~RECCF may designate a proposed or revised FRCC Regional Reliability Standard as requiring urgent action. Urgent action may be appropriate when a delay in implementing a proposed or revised FRCC Regional Reliability Standard will materially impact reliability of the Bulk Power System in the FRCC Region. The FRCC ~~OC and/or the PC~~RECCF must use its judgment carefully to ensure an urgent action is truly necessary and not simply an expedient way to change or implement a FRCC Regional Reliability Standard.

The entity making the request, or the FRCC ~~OC and/or the PC~~RECCF, will prepare a draft of the proposed FRCC Regional Reliability Standard and submit it to the FRCC Standards ~~Process Manager~~and Registration staff for urgent action. The submission must include a justification for the urgent action. ~~The~~FRCC Standards ~~Process Manager~~and Registration staff shall immediately ~~post~~ without delay initiate the *FRCC Regional Reliability Standards Development Process* by posting the draft as specified in Step 5. The posting shall be a

minimum of ten (10) calendar days before the ~~RBB~~Registered Ballot Body can consider the draft for approval. All comments received during the posting will be considered. Once approved by the ~~RBB~~Registered Ballot Body, the proposed urgent FRCC Regional Reliability Standard will be sent to the FRCC Board of Directors for adoption.

A FRCC Regional Reliability Standard that is adopted by the FRCC Board of Directors, as an urgent action shall have a termination date specified that shall not exceed one hundred eighty (180) calendar days from the approved date. Should there be a need to make the FRCC Regional Reliability Standard permanent, the replacement FRCC Regional Reliability Standard would be required to go through the full standards development process.

An urgent action FRCC Regional Reliability Standard that expires may be renewed by the FRCC Board of Directors using the urgent action process again, in the event a permanent FRCC Regional Reliability Standard has not been adopted. In determining whether to authorize the extension of an urgent action FRCC Regional Reliability Standard~~,~~ the FRCC ~~OC and/or the PC~~Board of Directors will request the FRCC RECCF to provide a recommendation to the Board. The FRCC RECCF shall consider the impact to the reliability of the FRCC Bulk ~~Electric~~Power System of not continuing the FRCC Regional Reliability Standard~~. In addition,~~ and consideration will be given to whether expeditious progress is being made toward a permanent replacement.

The FRCC ~~OC and/or the PC~~RECCF shall not request the FRCC Board of Directors to extend an urgent action FRCC Regional Reliability Standard if there is insufficient progress toward adopting a permanent replacement FRCC Regional Standard or if the FRCC ~~OC and/or the PC~~RECCF lack confidence that a reasonable completion date is achievable. The intent is to ensure that an urgent action FRCC Regional Reliability Standard does not in effect take on a degree of permanence due to the lack of an expeditious effort to develop a permanent replacement FRCC Regional Reliability Standard. With these principles, there is no pre-determined limit on the number of times an urgent action may be renewed. ~~However, each~~

Each urgent action FRCC Regional Reliability Standard renewal shall be effective only upon adoption by the FRCC Board of Directors, and approval by NERC and FERC.

~~*Interpretations of Standards*~~

3.5.2 Regional Definition Development

NERC maintains a glossary of approved terms, entitled the "Glossary of Terms Used in NERC Reliability Standards." The glossary includes terms that have been through the formal approval process and are used in one or more NERC Reliability Standards. There are two sections to the glossary. The first section includes definitions for terms used in continent-wide standards, and the second section includes definitions for terms used in Regional standards that have been adopted by the NERC Board of Trustees. The *Glossary of Terms* is intended to provide consistency throughout the Reliability Standards.

There are several methods that can be used to add, modify or retire a defined term used in a FRCC Regional Reliability Standard.

- Anyone can use a SAR to submit a request to add, modify, or retire a defined term.
- A drafting team may propose to add, modify, or retire a defined term in conjunction with the work it is already performing.

The following considerations should be made when considering proposals for new or revised definitions:

- Regional Entities have defined terms that have been approved for use in Regional Reliability Standards, and where the drafting team agrees with a term already defined by another Region, the same definition should be adopted if needed to support an FRCC Regional Reliability Standard.
- If a term is used in a Reliability Standard according to its common meaning (as found in a collegiate dictionary), the term shall not be proposed for addition to the *Glossary of Terms Used in NERC Reliability Standards*.
- If a term has already been defined, any proposal to modify or delete that term shall consider all uses of the definition in approved standards, with a goal of determining whether the proposed modification is acceptable, and whether the proposed modification would change the scope or intent of any approved standards.
- When practical, where the North American Energy Standards Board (NAESB) has a definition for a term, the drafting team shall use the same definition to support a NERC standard.

Any definition that is balloted separately from a proposed new or modified standard or from a proposal for retirement of a standard shall be accompanied by an implementation plan.

If a SAR is submitted to the FRCC Standards and Registration staff with a proposal for a new or revised definition, the FRCC RECCF shall consider the urgency of developing the new or revised definition and may direct FRCC Standards and Registration staff to post the SAR immediately, or may defer posting the SAR until a later time based on its priority relative to other projects already underway or already approved for future development. If the SAR

identifies a term that is used in a standard already under revision by a drafting team, the FRCC RECCF may direct the drafting team to add the term to the scope of the existing project. Any proposal for a new or revised definition shall be processed in accordance with Section III. *Steps in Developing a FRCC Regional Reliability Standard* of this procedure.

~~Any member of the~~ ~~FRCC, or group within the FRCC, or an entity that is directly and materially affected by reliability of the FRCC Bulk Power System shall be permitted to request an interpretation of a FRCC Regional Reliability Standard. The entity requesting an interpretation shall send a request to the FRCC Standards Process Manager explaining the specific circumstances surrounding the request and what clarifications are required as applied to those circumstances. The request should indicate the material impact to the requesting party, or others, caused by the lack of clarity or a possible incorrect interpretation of the FRCC Regional Reliability Standard. The FRCC Standards Process Manager will assemble a team with the relevant expertise to address the clarification.~~

~~As~~ ~~soon as practical (but not more than thirty (30) calendar days following the receipt of the request), the team will draft a written interpretation of the FRCC Regional Reliability Standard addressing the issues raised. The FRCC Standards Process Manager will submit the written interpretation to the OC and/or PC for review and approval. If approved by the FRCC OC and/or the PC, the interpretation is appended to the FRCC Regional Reliability Standard and is effective immediately. The interpretation will stand until such time as the FRCC Regional Reliability Standard is revised through the normal process, at which time the FRCC Regional Reliability Standard will be modified to incorporate the clarifications provided by the interpretation.~~

~~1.3.2~~3.5.3 Appeals

Any member of the FRCC, or group within the FRCC, or any entity that is directly and materially affected by reliability of the FRCC Bulk Power System, and who feel they have been or will be adversely affected by any ~~substantive or~~ procedural action or inaction related to the development, approval, revision, or withdrawal of a FRCC Regional Reliability Standard shall have the right to appeal. This appeals process applies only to the *FRCC Regional Reliability Standards Process* as defined in this document.

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. The final decisions of any appeal shall be documented in writing and posted on the FRCC public website. Notice of the posting will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator.

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

~~1.3.2.1~~3.5.3.1 Level 1 Appeal

Level 1 is the required first step in this appeals process. The appellant submits to the FRCC Manager of Standards ~~Process Manager~~and Registration a complaint in writing that describes the substantive or procedural action associated with a FRCC Regional Reliability Standard or the *FRCC Regional Reliability Standards Process*. The appellant ~~describes~~must describe in the complaint, the actual or potential adverse impact to the appellant. Assisted by any necessary staff and committee resources, the FRCC Manager of Standards ~~Process Manager~~and Registration 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 record associated with the FRCC Regional Reliability Standard.

~~1.3.2.2~~3.5.3.2 Level 2 Appeal

If after the Level 1 Appeal, the appellant remains unsatisfied with the resolution, notification shall be made in writing to the FRCC Manager of Standards ~~Process Manager.~~and Registration. Within thirty (30) calendar days of receiving the notification, the FRCC Manager of Standards ~~Process Manager~~and Registration shall convene a Level 2 Appeals Panel. This panel shall consist of five members appointed by the FRCC Board of Directors. In all cases, Level 2 Appeals Panel members shall have no direct affiliation with the participants in the appeal.

The FRCC Manager of Standards ~~Process Manager~~and Registration shall post on the FRCC public website the notice of the Level 2 appeal and other relevant materials. Notice of the posting will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator. At least fifteen (15) calendar days' notice of the meeting of the Level 2 Appeals Panel will be made. In addition to the appellant, any entity that is directly and materially affected by the reliability of the FRCC Bulk Power System, and who is directly and materially affected by the substantive or procedural action referenced in the complaint shall be heard by the panel.

The Level 2 Appeals Panel shall not consider any expansion of the scope of the appeal that was not presented in the Level 1 Appeal. The Level 2 Appeals Panel may in its decision find for the appellant and remand the issue to the FRCC ~~OC and/or the PC~~RECCF for resolution with a statement of the issues and facts in regard to which fair and equitable action was not taken. The Level 2 Appeals Panel may find against the appellant with a specific statement of the facts that demonstrate fair and equitable treatment of the appellant and the appellant's objections.

The Level 2 Appeals Panel may not, however, revise, approve, disapprove, or adopt a FRCC Regional Reliability Standard, as these responsibilities remain with the FRCC Board of Directors. The actions of the Level 2 Appeals Panel shall be posted on the FRCC public website. Notice of the posting will be sent to (1) the Registered Ballot ~~body~~Body, (2) the FRCC standing committees, subcommittees and working groups, (3)

the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator.

~~1.4~~3.6 ~~VI.~~ Maintenance of the FRCC Regional Reliability Standards and Process

~~1.4.1~~3.6.1 Requests to Revise the FRCC Regional Reliability Standard Development Process

Any member of the FRCC, or group (i.e. committee, subcommittee, working group or task force) within the FRCC, or any entity that is directly and materially affected by the reliability of the FRCC Bulk Power System may submit a written request to modify the *FRCC Regional Reliability Standard Development Process Manual*. The FRCC Standards ~~Process Manager~~and Registration staff shall oversee the handling of the request. ~~-~~The FRCC ~~OC~~Standards and~~/or the PC~~ Registration staff shall ~~review the request and submit recommendations~~prioritize all requests, merge related requests, and respond to ~~the FRCC Board of Directors for consideration. The FRCC Board of Directors, on its own motion, may amend the FRCC Regional Reliability Standard Process.~~ each requestor within thirty (30) calendar days.

The FRCC Standards and Registration staff shall post the proposed revisions for a thirty (30) calendar day formal comment period. Based on the degree of consensus for the revisions, the FRCC Standards and Registration staff shall:

a.) Submit the revised process or processes for Ballot Pool approval;
b.) Repeat the posting for additional inputs after making changes based on comments received;
c.) Remand the proposal to the requestor for further work; or
d.) Reject the proposal.

The Registered Ballot Body shall be represented by a Ballot Pool. The ballot procedure shall be the same as that defined for approval of a FRCC Regional Reliability Standard, including the use of subsequent ballots (additional or Final Ballots), as necessary. If the proposed revision is approved by the Ballot Pool, the FRCC Standards and Registration staff shall submit the revised procedure to the FRCC Board of Directors for adoption. The FRCC Standards and Registration staff shall submit to the board a description of the basis for the changes, a summary of the comments received, and any minority views expressed in the comment and ballot process. The proposed revisions shall not be effective until approved by the NERC Board of Trustees and applicable governmental authorities.

~~1.4.2~~3.6.2 Five-Year Review of FRCC Regional Reliability Standards

Each FRCC Regional Reliability Standard developed through *FRCC Regional Reliability Standard Development Process* shall be reviewed at least once every five ~~(5)~~ years~~. The review date will be determined~~ from the effective date ~~or~~of the ~~latest revision date whichever.~~ standard.

If a FRCC Regional Reliability Standard is ~~later. The~~nearing its five-year review and has issues that need resolution, then a FRCC Regional Reliability Standard Development project will be initiated for the complete review ~~process shall be conducted~~and associated revision of that standard that includes addressing all outstanding governmental directives and all unresolved issues identified by stakeholders. The standard development project will be processed in accordance with Section III. *Steps* ~~1 through 10 of the~~*in Developing a FRCC Regional Reliability Standard* ~~Development Process Manual. As a result~~ of this procedure.

If a FRCC Regional Reliability Standard is nearing its five-year review~~, a FRCC Regional Reliability Standard shall~~ and there are no outstanding governmental directives or unresolved stakeholder issues associated with that standard, then a FRCC Regional Reliability Standard Development project will be initiated solely for the "five-year review" of that standard and will be addressed by the following process.

For a project that is focused solely on the five-year review, the FRCC RECCF shall appoint a review team of subject matter experts to review the FRCC Regional Reliability Standard and recommend whether the standard should be reaffirmed, revised, or withdrawn. Each review team shall post its recommendations for a thirty (30) calendar day formal stakeholder comment period and shall provide those stakeholder comments to the FRCC RECCF for consideration.

- If a review team recommends reaffirming a FRCC Regional Reliability Standard, the FRCC RECCF shall submit the reaffirmation to the FRCC Board of Directors for concurrence. Reaffirmation does not require approval by stakeholder ballot.

- If a review team recommends modifying or withdrawing a FRCC Regional Reliability Standard, the team shall develop a SAR with such a proposal and the SAR shall be submitted to the FRCC RECCF for acceptance as a new project. Each existing standard recommended for modification or withdrawal shall remain in effect in accordance with the associated implementation plan until the action to modify or withdraw the standard is approved by its ballot pool, adopted by the FRCC Board of Directors, and approved by applicable governmental authorities.

In the case of reaffirmation of a FRCC Regional Reliability Standard, the standard shall remain in effect pending the results of the next five-year review or until the standard is otherwise modified or withdrawn by a separate action.

~~1.4.3~~3.6.3 Filing of FRCC Regional Standards with Regulatory Agencies

All adopted FRCC Regional Reliability Standards will be filed with ~~FERC~~the NERC Board of Trustees for adoption and subsequently filed with FERC for approval.

~~APPENDIX~~

4.0 References

Ten Benchmarks for Excellent Reliability Standards
FRCC Bylaws
NERC Regional Standards Review Procedure
NERC Glossary of Terms Used in Reliability Standards
NERC Regional Reliability Standards Evaluation Procedure

5.0 Attachments

Attachment A

~~Email completed form to FRCCStandard@frcc.com~~

: FRCC Regional Reliability Standard ~~Request~~Authorization Form

Attachment B: Process Diagram

Attachment C: Development of and Voting of the Registered Ballot Body

6.0 Review and Modification History

Review and Modification Log			
Date	Version Number	~~Title of Proposed Standard~~ Description of Review or Modification	Sections Affected
TBD	1	Revised Procedure/New Template	All
9/25/2007	0	Amended	All
10/24/2006	0	Amended	All
7/25/2006	0	Amended	All
3/2/2006	0	New Process	All

Attachment A

FRCC
Florida Reliability Coordinating Council, Inc.

FLORIDA RELIABILITY COORDINATING COUNCIL, INC.
3000 BAYPORT DRIVE, SUITE 600
TAMPA, FLORIDA 33607-8410
PHONE 813.289.5644 • FAX 813.289.5646
WWW.FRCC.COM

FRCC Regional Reliability Standard Request Form

Email completed form to FRCCStandard@frcc.com

Title of Standard
Request Date

Requestor Information	**TYPE** *(Check a box for each one that applies)*
Name	☐ New Standard
Primary Contact	☐ Revision to existing Standard
Telephone Fax	☐ Withdrawal of existing Standard
Email	☐ Urgent Action

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

Industry Need (Provide at a ~~detailed statement justifying~~minimum, a discussion of the ~~need for~~reliability-related impact of not developing the ~~proposed~~new standard, ~~along with any supporting documentation)~~and a technical foundation document (e.g., research paper), when needed, to guide the development of the 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~~)~~).

FRCC Regional Reliability Standard Request Form (cont.)

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

☐	Reliability Coordinator	~~Ensures~~Responsible for the real-time operating reliability of ~~the bulk transmission system within its~~ it Reliability ~~Authority~~Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area~~.~~ view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its ~~metered boundary~~balancing authority and supports system frequency in real time.
☐	Planning Authority	~~Plans the Bulk Electric System~~Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a ~~long term~~one-year plan for the resource adequacy of specific loads within a Planning ~~Authority~~Coordinator area
☐	Transmission Planner	Develops a ~~long term~~one-year plan for the reliability of ~~transmission systems~~the interconnected Bulk Electric System within its portion of the Planning ~~Authority~~Coordinator area.
☐	Transmission Service Provider	~~Provides~~Administers the transmission tariff and provides the transmission services ~~to qualified market~~under applicable transmission service agreements (e.g., the pro forma tariff).
☐ ☐	Transmission Owner	Owns and maintains transmission facilities
☐	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders.
☐	Distribution Provider	~~Provides and operates~~Delivers electrical energy to the ~~"wires" between the transmission system and the~~end-use customer.
☐	Generator Owner	Owns and maintains generation ~~unit(s)~~facilities.
☐	Generator Operator	Operates generation units(s) to provide real and ~~performs the functions of supplying energy and Interconnected Operations Services~~reactive power.
☐	~~Purchasing-Selling Entity~~	~~The function of purchasing or selling energy, capacity, and all necessary Interconnected Operations Services as required~~
☐	~~Load-Serving Entity~~	~~Secures energy and transmission (and related generation services) to serve the end user~~

~~FRCC Regional Reliability Standard Request Form~~

FRCC Regional Reliability Standard Request Form (cont.)

NERC Reliability Principles

Applicable Reliability Principles (Check box for all that apply.)	
☐	1. Interconnected ~~bulk electric systems~~Bulk Electric Systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected ~~bulk electric systems~~Bulk Electric 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 electric systems~~Bulk Electric 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 electric systems~~Bulk Electric 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 electric systems.~~Bulk Electric Systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored, and maintained on a wide-area basis.

FRCC Regional Reliability Standard Request Form (cont.)

NERC Market Interface Principles

Does the proposed Standard comply with all of the following Market Interface Principles?	
~~Recognizing that reliability is an essential requirement of a robust North American economy:~~	
yes or no ☐ ☐	1. A ~~reliability standard~~Reliability Standard shall not give any market participant an unfair competitive advantage.
yes or no ☐ ☐	2. A ~~reliability standard~~Reliability Standard shall neither mandate nor prohibit any specific market structure.
yes or no ☐ ☐	3. A ~~reliability standard~~Reliability Standard shall not preclude market solutions to achieving compliance with that standard.
yes or no ☐ ☐	4. A ~~reliability standard~~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.~~Reliability Standards.

~~FRCC Regional Reliability Standard Request Form~~

Related Standards

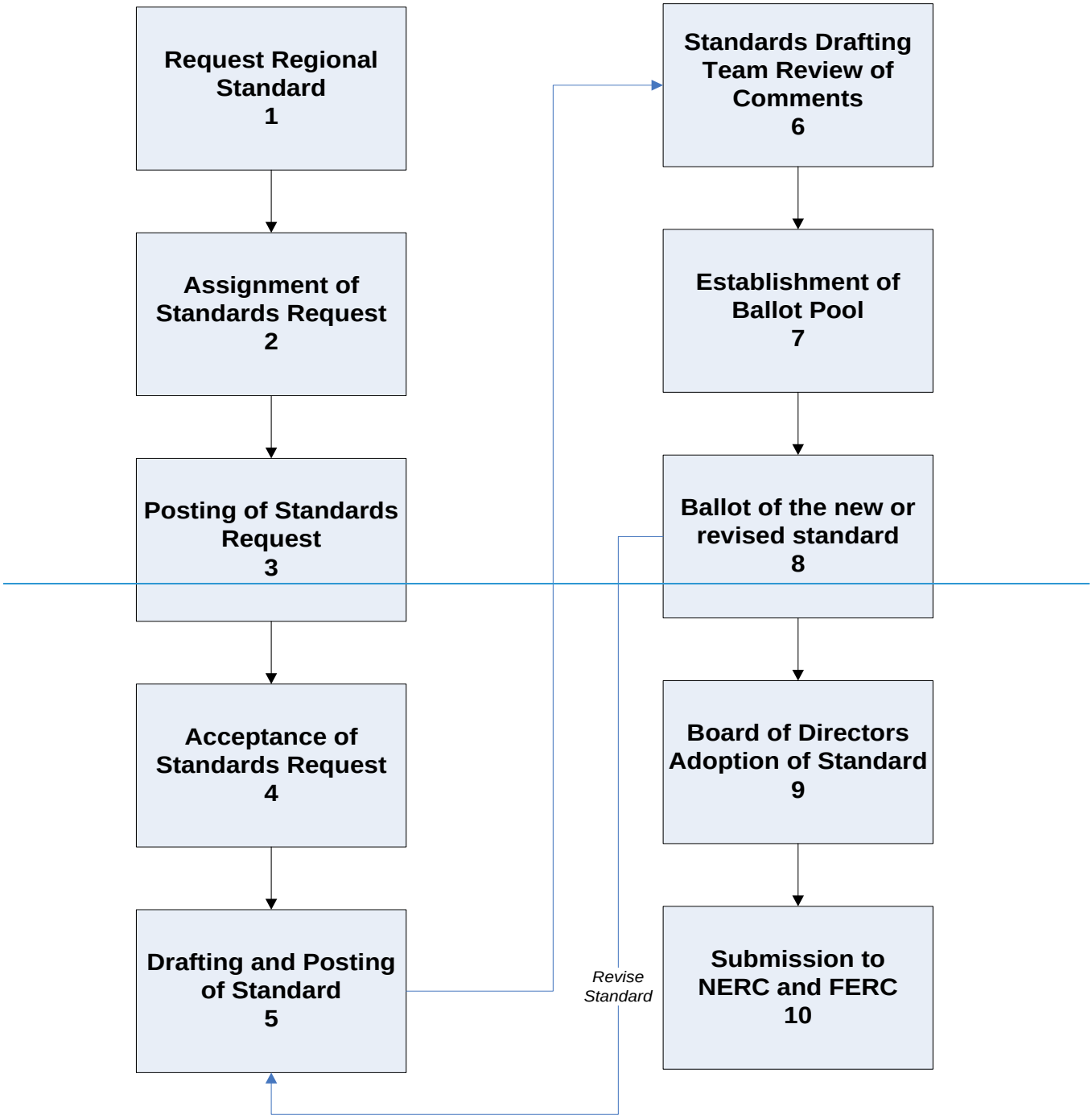
Standard No.	Explanation

~~**Proposed Implementation _____ days after Board of Directors adoption or**~~

~~**On (date):**~~

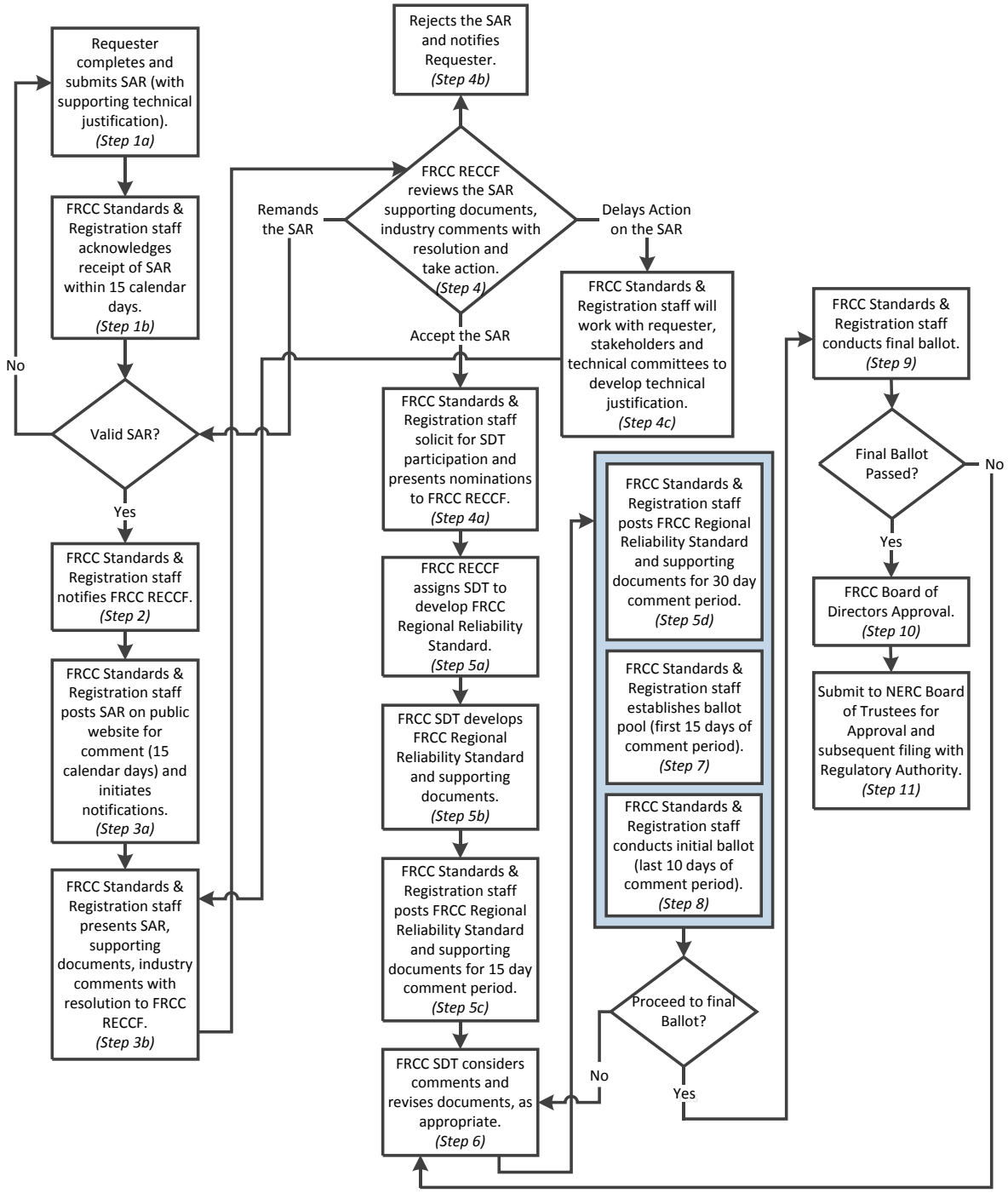
~~APPENDIX B~~

Process Diagram



~~APPENDIX~~

Attachment B
FRCC Regional Reliability Standard Development Process Flowchart


Requester completes and submits SAR (with supporting technical justification). (Step 1a)
FRCC Standards & Registration staff acknowledges receipt of SAR within 15 calendar days. (Step 1b)
Valid SAR?
No
Yes
FRCC Standards & Registration staff notifies FRCC RECCF. (Step 2)
FRCC Standards & Registration staff posts SAR on public website for comment (15 calendar days) and initiates notifications. (Step 3a)
FRCC Standards & Registration staff presents SAR, supporting documents, industry comments with resolution to FRCC RECCF. (Step 3b)
Rejects the SAR and notifies Requester. (Step 4b)
FRCC RECCF reviews the SAR supporting documents, industry comments with resolution and take action. (Step 4)
Remands the SAR
Delays Action on the SAR
Accept the SAR
FRCC Standards & Registration staff will work with requester, stakeholders and technical committees to develop technical justification. (Step 4c)
FRCC Standards & Registration staff solicit for SDT participation and presents nominations to FRCC RECCF. (Step 4a)
FRCC RECCF assigns SDT to develop FRCC Regional Reliability Standard. (Step 5a)
FRCC SDT develops FRCC Regional Reliability Standard and supporting documents. (Step 5b)
FRCC Standards & Registration staff posts FRCC Regional Reliability Standard and supporting documents for 15 day comment period. (Step 5c)
FRCC SDT considers comments and revises documents, as appropriate. (Step 6)
FRCC Standards & Registration staff posts FRCC Regional Reliability Standard and supporting documents for 30 day comment period. (Step 5d)
FRCC Standards & Registration staff establishes ballot pool (first 15 days of comment period). (Step 7)
FRCC Standards & Registration staff conducts initial ballot (last 10 days of comment period). (Step 8)
Proceed to final Ballot?
No
Yes
FRCC Standards & Registration staff conducts final ballot. (Step 9)
Final Ballot Passed?
No
Yes
FRCC Board of Directors Approval. (Step 10)
Submit to NERC Board of Trustees for Approval and subsequent filing with Regulatory Authority. (Step 11)

Attachment C

FRCC
Florida Reliability Coordinating Council, Inc.

FLORIDA RELIABILITY COORDINATING COUNCIL, INC.
3000 BAYPORT DRIVE, SUITE 600
TAMPA, FLORIDA 33607-8410
PHONE 813.289.5644 • FAX 813.289.5646
WWW.FRCC.COM

Development of and Voting of the Registered Ballot Body

1. Registration Procedures

The Registered Ballot Body ~~(RBB)~~ comprises all entities[2] and persons that:

- Qualify for one of the FRCC Industry Sectors, and
- Are registered with the FRCC as potential ballot participants in the voting on FRCC Regional Reliability Standards.

All registrations will be done electronically. All entities and persons will self-select to belong to the ~~RBB.~~ Registered Ballot Body. The sectors shall be identical to those in Section 1.2 of the *FRCC Bylaws*.

All ~~RBB~~Registered Ballot Body members will have the ability to vote on a standard. Voting will be done in writing (either email or facsimile) with each ~~RBB~~Registered Ballot Body member having one vote. The ~~RBB~~Registered Ballot Body representative will have the right to register and participate in ballot pools to cast their vote on a standard being considered for approval.

2. Sector Qualification Guidelines

The general guidelines are as follows:

- An entity or person may register in the ~~RBB~~Registered Ballot Body in any Sector in which it qualifies for provided that an entity or person registers as a potential ballot participant in only one (1) Sector.
- Any individual currently employed by an organization that is eligible to join one or more of the other five (5) sectors, shall not be qualified to join as a General Sector ~~RBB~~Registered Ballot Body member.

3. Ballot Pool Voting

[2] An entity and all of its Affiliates (as defined in the FRCC Bylaws) shall be considered one entity for purposes of registering as a potential ballot participant.

A Ballot Pool will be established to vote on any proposed standards action. Each ~~RBB~~Registered Ballot Body member choosing to belong to a Ballot Pool will have one individual vote. Two-thirds of the individual votes[3] of the Ballot Pool shall constitute a quorum.

Approval of a FRCC Regional Reliability Standard requires the affirmative vote of a two-thirds majority of the weighted sector votes cast. ~~The number of votes cast in each sector is the sum of the affirmative and negative votes, excluding abstentions.~~

The following steps will be used to determine if there ~~is~~are sufficient affirmative votes:

3.1. The number of affirmative votes cast in each sector will be divided by the sum of affirmative and negative votes cast to determine the fractional affirmative vote for each sector. ~~Abstentions~~Negative votes without comments and abstentions will not be counted.

3.2. The fractional affirmative vote for a sector will then be multiplied by the Sector Weight Factor to determine the weighted fractional affirmative vote for a sector.

The Sector Weight Factors are:

Suppliers Sector: Weight Factor = 2.5
Non-Investor Owned Utility Wholesale Sector: Weight Factor = 2.0
Load Serving Entity Sector: Weight Factor = 1.0
Generating Load Serving Entity Sector: Weight Factor = 3.0
Investor Owned Utility Sector: Weight Factor = 3.5
General Sector: Weight Factor = 1.0

~~3.2.~~**3.3.** The sum of the weighted fractional affirmative votes from all sectors divided by the sum of the weights of the sectors voting will be used to determine if a two-thirds majority has been achieved. A sector will be considered as "voting" if any member of the sector in the Ballot Pool casts either an affirmative or negative vote.

~~3.3.~~**3.4.** A FRCC Regional Reliability Standard will be considered "approved" if the sum of the weighted fractional affirmative votes from all sectors divided by the sum of the weights of the voting sectors is two-thirds or greater.

~~**3.4. History of Revisions**~~
~~Approved March 2, 2006~~

3.5. Each member of the Ballot Pool may vote one of the following positions:

Affirmative
Affirmative, with comment
Negative without comment

[3] Quorum is determined based on the individual votes cast (affirmative, negative, negative without comments and abstentions)

Negative with comments (if possible reasons should include specific wording or actions that would resolve the objection)
Abstain

3.6. Each Ballot Pool member submitting a negative vote with comments shall determine if the response provided by the drafting team satisfies those stated concerns. Each such balloter shall be informed of the appeals process contained within this manual.

3.7. If a standard achieves a quorum and there are no negative votes with comments from the initial ballot, and the overall approval is at least two thirds (weighted by segment) then the results of the Initial Ballot shall stand as final and the draft Reliability Standard and associated implementation plan shall be deemed to be approved by its Ballot Pool.

~~Amended~~ ~~July 25, 2006~~
~~Amended~~ ~~October 24, 2006~~
~~Amended September 25, 2007~~

ATTACHMENT 3:

Florida Reliability Coordinating Council Regional Reliability Standard Development Process Manual Revisions Summary Document

Original	Revision	Remarks
		Updated document to conform to new company-wide procedural template.
Section 3.0 FRCC Regional Reliability Standards Development Process		
Section 3.1 FRCC Regional Reliability Standard Principles		
Openness Participation is open to any interested party or any entity that is directly and materially affected by the reliability of the FRCC Bulk Power System. Participation shall not be conditional upon membership in the FRCC. All FRCC Regional Reliability Standard development meetings will be open and noticed on the FRCC website.	Open Participation – Participation in FRCC's regional standards development, balloting and approval processes is open to all entities that are directly and materially affected by FRCC reliability standard or the reliability of the FRCC Bulk Power System. There shall be no financial barriers to participation in the FRCC's regional standards development, balloting or approval processes. Participation in FRCC's regional standards development, balloting and approval processes shall not be conditional upon membership in any organization, nor unreasonably restricted on the basis of technical qualifications or other such requirements. All FRCC Regional Reliability Standard development meetings will be publically noticed on the FRCC website.	Provided additional clarifying verbiage to demonstrate that there are no barriers that would prevent any party or entity from participating in the FRCC Regional Standard Development Process.
Section 3.2.6 Elements of a Reliability Standard		
A FRCC Regional Reliability Standard shall consist of the elements identified in this section of this manual. These elements are intended to apply a systematic discipline in the development and revision of Reliability Standards. The format allows a clear statement	A FRCC Regional Reliability Standard includes many elements designed to work collectively to identify what entities must do to meet their reliability-related obligations as an owner, operator or user of the FRCC Bulk Power System. Elements that are considered mandatory and enforceable are identified below. The elements of a reliability standard include the following:	Provided additional clarifying verbiage in the introduction of the section to improve the text and style of language as well as to correct grammatical inconsistencies.
Section 3.2.7 Nomination, Modification, or Withdrawal of A Regional Standard		
	A FRCC Standard Authorization Request (SAR) is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified standards or the benefit of retiring one or more approved standards. Any entity or individual may propose the development of a new or modified	Introduction of the use of a Standard Authorization Request (SAR) in a more direct manner. Was not stated in the previous version of the process document.

	standard, or may propose the retirement of a standard, by submitting a completed SAR to the FRCC standards and registration staff at FRCCStandard@frcc.com. Each SAR that proposes a "new" standard, should be accompanied with a technical justification that includes, as a minimum, a discussion of the reliability-related impact of not developing the new standard, and a technical foundation document (e.g., research paper), when needed, to guide the development of the standard.	
Section 3.3.1 FRCC Board of Directors		
FRCC Board of Directors – The FRCC Board of Directors shall consider for adoption as FRCC Regional Reliability Standards, those Standards that have been developed and approved by this process. Once the Board adopts a FRCC Regional Reliability Standard, such Standard shall be submitted to NERC for approval. When approved by NERC, it will be submitted to FERC for approval.	The FRCC Board of Directors shall consider for adoption FRCC Regional Reliability Standards, definitions, and associated implementation plans that have been developed and approved by the processes identified in this manual. In addition, the board shall consider for approval, VRFs and VSLs associated with each approved standard. Once the Board adopts a FRCC Regional Reliability Standard, or definition, or once the Board approves VRFs or VSLs, the Board shall direct FRCC standards and registration staff to file the document(s) for approval with the applicable regulatory authorities.	Provided additional clarifying verbiage to include FRCC BOD responsibilities that were not specifically identified in the previous version of the document (i.e. consider for adoption 'definitions' and associated 'implementation plans'). Incorporated language to address the FRCC BOD responsibilities associated with VRFs and VSLs (VRFs and VSLs were not addressed in the previous version of the FRCC RRSPM.).
Section 3.3.4 FRCC Regional Entity Committee and Compliance Forum (RECCF)		
FRCC Operating Committee (OC) and FRCC Planning Committee (PC) – The FRCC OC and the FRCC PC (both of which are balanced stakeholder committees, see Appendix C) shall have the primary responsibility for the development, modification or withdrawal of FRCC Regional Reliability Standards.	The FRCC RECCF, a balanced stakeholder committee, is responsible for managing the standards processes for the development of standards, VRFs, VSLs, and definitions in accordance with this manual. The responsibilities of the FRCC RECCF are defined in detail in the committee scope document. Per Section 3.4 of this manual, the FRCC RECCF has the right to remand work to a drafting team, to reject the work of a drafting team, or to accept the	The FRCC Regional Entity (RE) Operating Committee (OC) and Regional Entity Planning Committee (PC) where the original committees responsible for oversight of the FRCC RRSDP. Reorganization of the committee structure at the FRCC RE resulted in the elimination of the FRCC RE OC and PC and the establishment of the FRCC Regional Entity Committee and Compliance Forum (RECCF). Updated language to reflect the RECCF as the new oversight authority for the FRCC RRSDP. The RECCF committee scope document

	work of a drafting team. The FRCC RECCF may direct a drafting team to revise its work to follow the processes in this manual or to meet the criteria for the ERO's benchmarks for reliability standards, or to meet the criteria for governmental approval, however the FRCC RECCF shall not direct a drafting team to change the technical content of a draft standard. The FRCC RECCF shall meet at regularly scheduled intervals (either in person, or by other means). At the invitation of the FRCC RECCF Chair, interested parties may attend committee meetings as guests when actions related to the standards development process are being discussed or acted on. Committee guests shall not be permitted to participate in committee voting and may not be counted in determining the existence of a quorum.	will be updated following regulatory approval of the FRCC RRSDP. Section 3.4 has been updated to identify specific responsibilities associated with the oversight activities of the FRCC RECCF.
Section 3.3.5 FRCC Standards and Registration Staff		
FRCC Standards Process Manager – The FRCC Regional Reliability Standard Development Process shall be administered by the FRCC Standards Process Manager. The FRCC Standards Process Manager will ensure the integrity of the process and the consistency of quality and completeness of the FRCC Regional Reliability Standards. The FRCC Standards Process Manager will facilitate all steps in this process, and will coordinate with NERC to ensure required information is posted on both NERC and FRCC websites.	The FRCC standards and registration staff, led by the Manager of Standards and Registration, is responsible for administering FRCC's Reliability Standards Processes in accordance with this manual. The standards and registration staff provides support to the FRCC RECCF in managing the standards processes and supporting the work of all drafting teams. The standards and registration staff work to ensure the integrity of the standards processes and consistency of quality and completeness of the reliability standards. The standards and registration staff facilitates all steps in the development of standards, definitions, and associated implementation plans. The standards and registration staff work with drafting teams in developing VRFs and VSLs for each standard. The FRCC standards and registration staff shall coordinate a quality review of the "final draft" of the reliability standard, it's implementation plan, and VRFs and VSLs to assess whether the	Provided additional clarifying verbiage to include FRCC Standards and Registration staff's responsibilities that were not specifically identified in the previous version of the document. Incorporated language to specifically address the FRCC Standards and Registration staff's responsibilities associated with VRFs and VSLs development (VRFs and VSLs were not addressed in the previous version of the FRCC RRSPM.), staff reviews of Standard Development documents and coordination with the RECCF.

	documents are within the scope of the associated SAR, whether the standard is clear and enforceable as written, and whether the standard meets the criteria specified in the NERC and FERC guidelines. This review shall normally be completed within thirty (30) calendar days[1] of receipt of the final version of the documents from the Standard Drafting Team (SDT). The detailed results of this review shall be provided to the SDT and the FRCC RECCF with a recommendation on whether the documents are ready for formal posting and balloting. If the FRCC RECCF agrees that the proposed reliability standard, implementation plan, and VRFs and VSLs pass this review, the FRCC RECCF shall authorize posting for a formal comment period, ballot (for the standard and implementation plan), and non-binding poll (for VRFs and VSLs) as soon as the work flow will accommodate. If the FRCC RECCF finds that any of the documents do not meet the specified criteria, the FRCC RECCF shall remand the documents to the SDT for additional work. If the standard is outside the scope of the associated SAR, the SDT shall be directed to either revise the standard so that it is within the approved scope, or submit a request to expand the scope of the approved SAR. If the standard is not clear and enforceable as written, or if the standard or its VRFs and/or VSLs do not meet the specified criteria, the standard shall be returned to the SDT with specific identification of any requirement that is deemed to be unclear or unenforceable as written.	

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

	The standards and registration staff is responsible for presenting standards, and definitions to the FRCC Board of Directors for adoption. When presenting standards-related documents to the FRCC Board of Directors for adoption or approval, the standards and registration staff shall report the results of the associated stakeholder ballot, including identification of any unresolved minority stakeholder issues.	
Section 3.3.6 Drafting Teams		
Standard Drafting Team – A team of technical experts, such as FRCC Subcommittees. Working Groups, Task Forces, or the FRCC Staff, will be appointed by the FRCC OC and/or PC that will: Develop the details of the FRCC Regional Reliability Standards, Consider and respond to industry comments, Participate in forums to help build consensus on draft FRCCC Regional Reliability Standards, Assist in the implementation of approved FRCC Regional Reliability Standards Provide technical oversight in response to changing industry conditions, Assist in the identification of the needed for new FRCC Regional Reliability Standards.	The FRCC RECCF shall appoint industry subject matter experts to drafting teams to work with stakeholders in developing and refining SARs, standards, VRFs, VSLs and definitions. Each drafting team consists of a group of technical experts that work cooperatively with the support of the standards and registration staff. The technical experts provide subject matter expertise and guide the development of the technical aspects of the standard. The technical experts maintain authority over the technical details of the standard. Each drafting team appointed to develop a standard is responsible for following the processes identified in this manual as well as procedures developed by the FRCC RECCF from the inception of the assigned project through the final acceptance of that project by applicable governmental authorities. Collectively, each drafting team will: Draft proposed language for the reliability standards, definitions, and associated implementation plans. Solicit, consider, and respond to comments related to the specific standards development project.	Provided additional clarifying verbiage to include responsibilities associated with the establishment of Standard Drafting Teams (SDTs). Additionally, provided clarifying verbiage to include the responsibilities of the SDT that were not specifically identified in the previous version of the document. For example: incorporated language to specifically address the FRCC SDT responsibilities associated with drafting of standard, definition and/or implementation plans, the use of informal and formal consensus building through participation in various industry forums, VRFs and VSLs development (VRFs and VSLs were not addressed in the previous version of the FRCC RRSPM.) and the reporting relationship with the RECCF.

	Participate in industry forums to help build consensus on the draft reliability standards, definitions, and associated implementation plans. Assist in developing the documentation used to obtain approval and subsequent filing of the reliability standards, definitions and associated implementation plans. The FRCC standards and registration staff shall provide a member to support the team with technical writing expertise and shall provide administrative support to the team, guiding the team through the steps in completing its project. The individuals provided by the standards and registration staff serve as advisors to the drafting team and do not have voting rights. The FRCC RECCF may also supplement the membership of a standard drafting team at any time to ensure the necessary competencies and diversity of views are maintained throughout the standard development effort. All drafting teams report to the FRCC RECCF.	
Section 3.3.7 Governmental Authorities		
	The Federal Energy Regulatory Commission (FERC) in the United States of America has the authority to approve each new, revised or withdrawn reliability standard, definition, VRF, and VSL following adoption or approval by the NERC Board of Trustees.	Section was added to identify the role of the applicable government authority (i.e. The Federal Energy Regulatory Commission (FERC)).
3.3.8 FRCC Committees, Subcommittees, Working Groups, and Task Forces		
Subcommittees, Working Groups, Task Forces, or the FRCC Staff, will be appointed by the FRCC OC and/or PC, that will: Develop the details of the FRCC Regional Reliability Standard, Consider and respond to industry comments,	FRCC's technical committees, subcommittees, working groups, and task forces may provide technical research and analysis used to justify the development of new standards and may provide guidance, when requested by the FRCC RECCF, in overseeing field tests or collection and analysis of data. The technical committees, subcommittees,	The FRCC Regional Entity (RE) Operating Committee (OC) and Regional Entity Planning Committee (PC) where the original committees responsible for oversight of the FRCC RRSDP. Reorganization of the committee structure at the FRCC RE resulted in the elimination of the FRCC RE OC and PC and the establishment of the FRCC

Participate in forums to help build consensus on draft FRCC Regional Reliability Standards, Assist in the implementation of approved FRCC Regional Reliability Standards, Provide technical oversight in response to changing industry conditions, Assist in the identification of the need for new FRCC Regional Reliability Standards.	working groups, and task forces may provide feedback to drafting teams during both informal and formal comment periods. The technical committees, subcommittees, working groups, and task forces share their observations regarding the need for new or modified standards or requirements with the standards and registration staff for use in identifying the need for new standards projects.	Regional Entity Committee and Compliance Forum (RECCF). Updated language to clarify the relationship between the RECCF and the FRCC's technical committees, subcommittees, working groups, and task forces.
Section 3.4.1 Step 1 – Request a new FRCC Regional Reliability Standard or modification to, or withdrawal of an existing FRCC Regional Reliability Standard		
A request to develop, modify or withdraw a FRCC Regional Reliability Standard shall be submitted to the FRCC Standards Process Manager (via email to FRCCStandard@frcc.com) by any member of the FRCC, or group (i.e. committee, subcommittee, working group or task force) within the FRCC, or any interested party or any entity that is directly and materially affected by reliability of the FRCC Bulk Power System. The FRCC Standards Process Manager will acknowledge receipt of the request within fifteen (15) calendar days of its receipt.	Step 1a - A Standard Authorization Request (SAR) to develop, modify or withdraw a FRCC Regional Reliability Standard shall be submitted to the FRCC Standards and Registration staff (via email to FRCCStandard@frcc.com) by any member of the FRCC, or group (i.e. committee, subcommittee, working group or task force) within the FRCC, or any interested party or any entity that is directly and materially affected by reliability of the FRCC Bulk Power System. Step 1b - The FRCC Standards and Registration staff shall acknowledge receipt of the request within fifteen (15) calendar days of its receipt.	Introduced language to identify the use of the Standard Authorization Request (SAR) as the mechanism to request the development, modification or withdrawal of a FRCC Regional Reliability Standard. Provided additional clarifying verbiage on the responsibilities of the FRCC Standards and Registration staff.
Section 3.4.3 Step 3a – Posting of FRCC Regional Reliability Standard Request		
The request for standard development, modification or withdrawal will be posted for notification and comment on the FRCC public website for a period of fifteen (15) calendar days, and will be reviewed by the FRCC OC and/or PC. A notice of the posting for comment will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator to seek input on the proposed request.	The SAR will be posted for notification and comment on the FRCC public website for a period of fifteen (15) calendar days. For SARs that address the development of a new standard, the SAR will be posted for a fifteen (15) calendar day formal comment period. For SARs that are limited to modifications to or withdrawal of existing standards, the SAR will be posted for a fifteen (15) calendar day informal comment period.	Updated language to identify the use of the Standard Authorization Request (SAR) in this stage of the development process. Provided additional clarifying verbiage on 'formal' and 'informal' comments obtained through posting periods and the Drafting Teams obligations in responding to comments (formal and/or informal). Updated language to reflect the involvement of the RECCF.

	The intent of the formal comment periods is to solicit very specific feedback on the SAR and technical justification. A written response to each comment received is required. Feedback gathered from the informal comment period shall be publicly posted and, while a written response to each individual comment received is not required, a summary response that identifies how the comments were considered is required. A notice of the posting for comment shall be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator. Step 3b - Following the comment period, the FRCC Standards and Registration staff shall present the SAR, supporting documents, industry comments with resolution to the FRCC RECCF for review.	
Section 3.4.4 Step 4 – Acceptance of a FRCC Regional Reliability Standard Request		
The FRCC OC and/or the PC will review the request and any comments submitted to determine if the request received will be accepted or rejected within sixty (60) days of its submission. The decision will be posted and, if accepted, the OC and/or the PC will assign and direct a Standard Drafting Team to develop the draft Regional Reliability Standard. If the request is rejected, the FRCC Standards Process Manager will send notification to the entity making the request and to all entities that received the notice in Step 3 above.	Step 4 - The FRCC RECCF reviews the SAR, supporting documents, industry comments and resolutions and takes one of the following actions: Accept the SAR. Remand the SAR back to the requester and FRCC Standards and Registration staff for additional work. The FRCC RECCF will provide a written explanation for the remand. Reject the SAR. If the FRCC RECCF rejects a SAR, a written explanation for rejection will be provided to the requester within ten (10) calendar days of the rejection decision.	Updated language to identify the use of the Standard Authorization Request (SAR) in this stage of the development process. Updated language to reflect the involvement of the RECCF. Provided additional clarifying verbiage on the RECCF responsibilities associated with SAR disposition and the solicitation and selection of SDT members.

	Delay action on the SAR pending development of a technical justification for the proposed project. The review decision will be publically posted. Step 4a - If accepted, the FRCC RECCF will seek industry volunteers, establish the SDT to further develop the SAR (if necessary), draft the Regional Reliability Standard and to address comments submitted during the posting periods. The FRCC Standards and Registration staff will publicly post a request for fifteen (15) calendar days soliciting industry volunteers to participate on the SDT. Step 4a.1 - FRCC Standards and Registration staff will present a list of qualified candidates to the FRCC RECCF for potential assignment to the SDT. Step 4b - If the request is rejected, the FRCC Standards and Registration staff will send notification to the entity making the request. Step 4c - If the FRCC RECCF is presented with a SAR that proposes developing a new standard but does not have a technical justification upon which the standard can be developed, the FRCC RECCF shall delay action and direct the FRCC Standards and Registration staff to post the SAR for a thirty (30) calendar day comment period solely to collect stakeholder feedback on the scope of technical foundation, if any, needed to support the proposed project. If a technical foundation is determined to be necessary, the FRCC RECCF shall solicit assistance from FRCC's technical committees or other industry experts in providing that foundation before authorizing development of the associated standard.	

Section 3.4.5 Step 5 – Drafting and Posting of a FRCC Regional Reliability Standard		
The FRCC OC and/or PC will assign a Standard Drafting Team, within 60 days of acceptance of the request, to develop, in a timely manner, a draft FRCC Regional Reliability Standard that will address the accepted request. The FRCC OC and/or PC may provide a timeframe that is desired for completion of the standard development. Under the direction of the FRCC OC and/or PC, the Standard Drafting Team, will consider all comments received on the posting of the standard request and will develop a draft FRCC Regional Reliability Standard and corresponding implementation plan. The draft FRCC Regional Reliability Standard, implementation plan and any supporting documents shall be posted for comments on the FRCC public website for a period of fifteen (15) calendar days, or such longer period as determined by the drafting team or as directed by the FRCC OC and/or the PC. Notice of the posting will go out to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator to seek comments. Comments shall be submitted (via email) to the FRCC Standards Process Manager (FRCCStandard@frcc.com). All comments are due by the close of business on the 15th calendar day of posting, or such later date as determined by the drafting team or as directed by the FRCC OC and/or PC. If the comment due date falls on a weekend or nationally recognized holiday, the comments shall be due by the close of business on the next regularly scheduled business day.	Step 5a - The FRCC RECCF will assign a SDT, within sixty (60) calendar days of acceptance of the request, to develop, in a timely manner, a draft FRCC Regional Reliability Standard that will address the accepted request. Step 5b - The SDT shall develop a project schedule and report progress, to the FRCC RECCF, against that schedule as requested by the FRCC RECCF. The SDT, shall consider all comments received on the posting of the SAR and shall develop a draft FRCC Regional Reliability Standard and corresponding implementation plan. The SDT shall develop a Reliability Standard that is within the scope of the associated SAR that includes all required elements as described earlier in this manual with a goal of meeting the quality attributes identified in the *Ten Benchmarks for Excellent Reliability Standards* and criteria for governmental approval. The team shall document its justification for the requirements in its proposed standard by explaining how each meets these criteria. As the SDT drafts a Reliability Standard, that team is also required to develop an implementation plan to identify any factors for consideration when approving the proposed effective date or dates for the associated standard or standards. A single implementation plan may be used for more than one standard. As a minimum, the implementation plan shall include the following: The proposed effective date (the date entities shall be compliant) for the requirements.	Updated process language to clarify individual ‘steps’. Updated language to reflect the involvement of the RECCF. Provided additional clarifying verbiage on the RECCF responsibilities associated with the formation of the SDT. Provided guidance to the SDT on Standard development, implementation plans and definitions (if appropriate). Introduced the SDT and FRCC Standards and Registration staff responsibilities associated with the development of VRFs and VSLs. Identified various methods for collecting industry feedback (i.e., formal and/or informal comment periods) and the process related obligations for each method. Introduced the ‘quality review’ of the new or modified standard, its associated VRFs and VSLs, and implementation plan.

	Identification of any new or modified definitions that are proposed for approval with the associated standard. Whether there are any prerequisite actions that need to be accomplished before entities are held responsible for compliance with one or more of the requirements. Whether approval of the proposed standard will necessitate any conforming changes to any already approved standards – and identification of those standards and requirements. The functional entities that will be required to comply with one or more requirements in the proposed standard. The SDT shall work with FRCC Standards and Registration staff in developing a set of VRFs and VSLs that meet the latest criteria established by the NERC and governmental authorities. The SDT shall document its justification for selecting each VRF and for setting each set of proposed VSLs by explaining how its proposed VRFs and VSLs meet these criteria. FRCC Standards and Registration staff is responsible for ensuring that the VRFs and VSLs proposed for stakeholder review meet these criteria. Before the SDT has finalized its standard, implementation plan, VRFs and VSLs, the SDT should seek stakeholder feedback on its preliminary draft documents. The SDT may use a variety of methods to collect stakeholder feedback on preliminary drafts of its documents, including the use of informal comment periods, webinars, industry meetings, workshops, or other mechanisms. Informal comment periods, if used, shall have a minimum duration of fifteen (15)	

	calendar days. Information gathered from informal comment forms shall be publicly posted and, while drafting teams are not required to provide a written response to each individual comment received, drafting teams must post a summary response that identifies how it used comments submitted by stakeholders. The intent is to gather stakeholder feedback on a "working document" before the document reaches the point where it is considered the "final draft." The FRCC Standards and Registration staff shall conduct a quality review of the new or modified standard, its associated VRFs and VSLs, and implementation plan prior to each posting. Step 5c - The initial formal comment period, and if necessary subsequent formal comment periods, shall be for at least thirty (30) calendar day duration and shall start after the SDT has posted its consideration of stakeholder comments and any conforming changes to the associated standard. The intent of the formal comment periods is to solicit very specific feedback on the final draft of the standard, VRFs, VSLs, and implementation plan. If stakeholders disagree with some aspect of the proposed set of products, comments provided should suggest specific language that would make the product acceptable to the stakeholder. Notice of the posting will go out to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator to seek comments.	

	Comments shall be submitted (via email) to the FRCC Standards and Registration staff (FRCCStandard@frcc.com). All comments are due by the close of business on the posted due date. If the comment due date falls on a weekend or nationally recognized holiday, the comments shall be due by the close of business on the next regularly scheduled business day.	
Section 3.4.8 Step 8 Initial – Ballot of the new or revised FRCC Regional Reliability Standard and Non-Binding Poll of VRFs and VSLs		
The FRCC Standards Process Manager will post the final draft of the standard on the FRCC website at least fifteen (15) calendar days before a ballot can begin. The Ballot Pool shall have a minimum of ten (10) calendar days to vote on a standard. The Ballot Pool may vote to approve or not approve the standard. If approved, the FRCC Standards Process Manager will submit the FRCC Regional Reliability Standard, proposed implementation plan, and any supporting documents to the FRCC Board of Directors for adoption. If approval by the Ballot Pool is not obtained, the PC and/or OC will determine if the draft standard is to be sent back to the standard drafting team to repeat step 6 to incorporate any comments, or to take no further action. If no further action is taken, the reason for such will be posted on the FRCC public website. A notice of the posting will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator.	The FRCC Standards and Registration staff shall announce the opening of the initial ballot window and the non-binding poll of VRFs and VSLs. The ballot window and non-binding poll window shall both take place during the last ten (10) calendar days of the thirty (30) calendar day formal comment period. This allows all stakeholders the opportunity to comment on the final draft of each proposed standard, even those stakeholders who are not members of the Ballot Pool. The ballot and non-binding poll shall be conducted electronically. The voting and polling windows shall each be a period of ten (10) calendar days but both shall be extended, if needed, until a quorum is achieved. During a ballot window, FRCC shall not sponsor or facilitate public discussion of the standard action under ballot. The SDT shall consider every stakeholder comment submitted either in response to a formal comment period or submitted with a ballot that includes a proposal for a specific modification to the standard or its implementation plan posted for comment and approval. The SDT shall be responsive to all comments by providing a written response and indicating whether the drafting team adopted or rejected any recommendations.	Updated process language to incorporate the use of ‘concurrent posting periods’ (i.e., Comment period, ballot pool formation and initial ballot during the same timeframe). Introduced the concept of non-binding polls of VRFs and VSLs. Clarified SDT and FRCC Standards and Registration staff responsibilities associated with comment responses and initial/additional ballot results.

	If stakeholders submit comments that indicate a specific improvement to one or more of the VRFs or VSLs and the modification would improve consensus without violating the criteria for setting VRFs and VSLs, then the SDT, working with FRCC Standards and Registration staff, shall consider and respond to each comment, and shall make conforming changes to reflect those comments. There is no requirement to conduct a new non-binding poll of the revised VRFs and VSLs if no changes were made to the associated standard; however, if the requirements are modified and conforming changes are made to the associated VRFs and VSLs, another non-binding poll of the revised VRFs and VSLs shall be conducted. All comments submitted and the responses to those comments shall be publicly posted. See Attachment C *Development of and Voting of the Registered Ballot Body* for ballot approval and quorum requirements. If a stakeholder or balloter proposes a significant revision to the standard during the formal comment period or concurrent initial ballot that will improve the quality, clarity, or enforceability of that standard then the SDT shall make such revisions and post the revised standard (that has been significantly changed from the previous ballot) for another public comment period and an additional ballot. The SDT shall address comments submitted during additional ballot periods (comments submitted from stakeholders during the open formal comment period and comments submitted with negative ballots) in the same manner as for the Initial Ballot. Once the SDT has a draft standard that has been	

	through an "additional ballot" and the team believes that no additional significant modifications are needed, or the SDT has reached a point where it has made a good faith effort at resolving applicable objections, the standard shall be posted for a Final Ballot.	
Section 3.4.9 Step 9 - Final Ballot - of the New or Revised FRCC Regional Reliability Standard		
	In the Final Ballot, members of the ballot pool shall again be presented the proposed standard (that has not been significantly changed from the previous ballot) along with the reasons for negative votes, the responses, and any resolution of the differences. An insignificant revision is a revision that does not change the scope, applicability, or intent of any requirement and includes but is not limited to things such as correcting the numbering of a requirement, correcting the spelling of a word, adding an obviously missing word, or rephrasing a requirement for improved clarity. Where there is a question as to whether a proposed modification is "substantive" the FRCC RECCF shall make the final determination. There is no formal comment period concurrent with the Final Ballot and no obligation for the SDT to respond to any comments submitted during the Final Ballot. All members of the Ballot Pool shall be permitted to reconsider and change their vote from the prior ballot. Members of the Ballot Pool who did not respond to the prior ballot shall be permitted to vote in the Final Ballot. In the Final Ballot, votes shall be counted by exception only. Members of the ballot pool for the Final Ballot may indicate a revision to their original vote otherwise their vote shall remain the same as in their prior ballot. There are no limits to the number of "additional" public comment periods and ballots that can be	Updated process language to clarify and include a process step defining the final ballot requirements. Updated language to reflect the involvement and responsibilities of the RECCF. Guidance is provided to members of the 'ballot pool' on the conduct of the final ballot.

	conducted to result in a standard that is clear and enforceable, and achieves a quorum and sufficient affirmative votes for approval. The FRCC RECCF has the authority to conclude this process or a particular standards action if it becomes obvious that the SDT cannot develop a standard that is within the scope of the associated SAR, is sufficiently clear to be enforceable, and achieves the requisite weighted segment approval percentage. The FRCC Standards and Registration staff shall post the final outcome of the ballot process. If the standard is approved, the consensus standard shall be posted and presented to the Board of Directors for adoption by the FRCC.	
Section 3.4.10 Step 10 – Adoption of FRCC Regional Reliability Standards and Implementation Plans by the FRCC Board of Directors		
At a regular or special meeting, the FRCC Board of Directors may consider adoption of the proposed FRCC Regional Reliability Standard that has been approved by the RBB Ballot Pool. A FRCC Regional Reliability Standard submitted for adoption by the FRCC Board of Directors must be posted for notification and comment on the FRCC public website at least ten (10) calendar days prior to action by the FRCC Board of Directors. Notice of the posting will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator. The FRCC Board of Directors shall consider the comments received, the responses provided, and any dissenting opinions. The FRCC Board of Directors shall adopt or reject a FRCC Regional Reliability Standard as submitted, but may not modify the proposed FRCC Regional Reliability Standard. If the FRCC Board of Directors chooses not to adopt a FRCC Regional Reliability Standard, it shall provide its reasons for not doing so.	At a regular or special meeting, the FRCC Board of Directors may consider adoption of the proposed FRCC Regional Reliability Standard and the associated implementation plan that have been approved by the Registered Ballot Pool. A FRCC Regional Reliability Standard and the associated implementation plan submitted for adoption by the FRCC Board of Directors must be posted for notification and comment on the FRCC public website at least ten (10) calendar days prior to action by the FRCC Board of Directors. Notice of the posting will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator. The FRCC Board of Directors shall consider the comments received, the responses provided, and any dissenting opinions. The FRCC Board of Directors shall adopt or reject a FRCC Regional Reliability Standard and the associated implementation plan as submitted, but may not modify the proposed FRCC Regional Reliability Standard. If the FRCC Board	Updated process language to clarify FRCC Board of Directors responsibilities associated with the adoption of a FRCC Regional Reliability Standard, VRFs, VSLs and associated implementation plans. Provided guidance to the FRCC Board of Directors on the approval of VRFs and VSLs. Further clarified FRCC Standards and Registration staff responsibilities.

If the FRCC Board of Directors chooses not to adopt the proposed FRCC Regional Reliability Standard, the reason for such decision will be posted on the FRCC public website. Notice of the posting will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator.	of Directors chooses not to adopt a FRCC Regional Reliability Standard, it shall provide its reasons for such decision and the decision will be posted on the FRCC public website. Notice of the posting will be sent to (1) the Registered Ballot Body, (2) the FRCC standing committees, subcommittees and working groups, (3) the Florida Public Service Commission, and (4) the SERC Southern Sub-Region Reliability Coordinator. The board shall consider approval of the VRFs and VSLs associated with a Reliability Standard. In making its determination, the board shall consider the following: FRCC Standards and Registration staff shall present the results of the non-binding poll conducted and a summary of industry comments received on the final posting of the proposed VRFs and VSLs. FRCC Standards and Registration staff shall present a set of recommended VRFs and VSLs that considers the views of the SDT, stakeholder comments received on the draft VRFs and VSLs during the posting for comment process, the non-binding poll results, appropriate governmental agency rules and directives, and VRF and VSL assignments for other Reliability Standards to ensure consistency and relevance across the entire spectrum of Reliability Standards.	
Section 3.5.2 Regional Definition Development		
	NERC maintains a glossary of approved terms, entitled the "Glossary of Terms Used in NERC Reliability Standards." The glossary includes terms that have been through the formal approval process and are used in one or more NERC Reliability Standards. There are two sections to the glossary. The first section includes definitions for terms used in continent-wide standards, and the second section	Section was added to establish a process for the development of defined terms that are used in FRCC Regional Reliability Standards. Provided language to reflect the involvement of the RECCF. Provided additional clarifying verbiage on the RECCF responsibilities associated with definition development.

	includes definitions for terms used in Regional standards that have been adopted by the NERC Board of Trustees. The Glossary of Terms is intended to provide consistency throughout the Reliability Standards. There are several methods that can be used to add, modify or retire a defined term used in a FRCC Regional Reliability Standard. Anyone can use a SAR to submit a request to add, modify, or retire a defined term. A drafting team may propose to add, modify, or retire a defined term in conjunction with the work it is already performing. The following considerations should be made when considering proposals for new or revised definitions: Regional Entities have defined terms that have been approved for use in Regional Reliability Standards, and where the drafting team agrees with a term already defined by another Region, the same definition should be adopted if needed to support an FRCC Regional Reliability Standard. If a term is used in a reliability standard according to its common meaning (as found in a collegiate dictionary), the term shall not be proposed for addition to the *Glossary of Terms Used in NERC Reliability Standards*. If a term has already been defined, any proposal to modify or delete that term shall consider all uses of the definition in approved standards, with a goal of determining whether the proposed modification is acceptable, and whether the proposed modification would change the scope or intent of any approved standards.	

	When practical, where the North American Energy Standards Board (NAESB) has a definition for a term, the drafting team shall use the same definition to support a NERC standard. Any definition that is balloted separately from a proposed new or modified standard or from a proposal for retirement of a standard shall be accompanied by an implementation plan. If a SAR is submitted to the FRCC Standards and Registration staff with a proposal for a new or revised definition, the FRCC RECCF shall consider the urgency of developing the new or revised definition and may direct FRCC Standards and Registration staff to post the SAR immediately, or may defer posting the SAR until a later time based on its priority relative to other projects already underway or already approved for future development. If the SAR identifies a term that is used in a standard already under revision by a drafting team, the FRCC RECCF may direct the drafting team to add the term to the scope of the existing project. Any proposal for a new or revised definition shall be processed in accordance with Section III. *Steps in Developing a FRCC Regional Reliability Standard* of this procedure.	
Section 3.6.1 Requests to Revise the FRCC Regional Reliability Standard Development Process		
Any member of the FRCC, or group (i.e. committee, subcommittee, working group or task force) within the FRCC, or any entity that is directly and materially affected by the reliability of the FRCC Bulk Power System may submit a written request to modify the *FRCC Regional Reliability Standard Development Process Manual*. The FRCC Standards Process Manager shall oversee the handling of the request. The FRCC OC and/or the PC shall review the request and submit	Any member of the FRCC, or group (i.e. committee, subcommittee, working group or task force) within the FRCC, or any entity that is directly and materially affected by the reliability of the FRCC Bulk Power System may submit a written request to modify the *FRCC Regional Reliability Standard Development Process Manual*. The FRCC Standards and Registration staff shall oversee the handling of the request. The FRCC Standards and Registration staff shall prioritize all requests, merge	Section was significantly expanded to provide clarifying verbiage in regards to process requirements and the role and responsibility of the FRCC Standards and Registration staff.

recommendations to the FRCC Board of Directors for consideration. The FRCC Board of Directors, on its own motion, may amend the FRCC Regional Reliability Standard Process.	related requests, and respond to each requestor within thirty (30) calendar days. The FRCC Standards and Registration staff shall post the proposed revisions for a thirty (30) calendar day formal comment period. Based on the degree of consensus for the revisions, the FRCC Standards and Registration staff shall: Submit the revised process or processes for Ballot Pool approval; Repeat the posting for additional inputs after making changes based on comments received; Remand the proposal to the requestor or for further work; or Reject the proposal. The Registered Ballot Body shall be represented by a Ballot Pool. The ballot procedure shall be the same as that defined for approval of a FRCC Regional Reliability Standard, including the use of subsequent ballots (additional or Final Ballots), as necessary. If the proposed revision is approved by the Ballot Pool, the FRCC Standards and Registration staff shall submit the revised procedure to the FRCC Board of Directors for adoption. The FRCC Standards and Registration staff shall submit to the board a description of the basis for the changes, a summary of the comments received, and any minority views expressed in the comment and ballot process. The proposed revisions shall not be effective until approved by the NERC Board of Trustees and applicable governmental authorities.	
Section 3.6.2 Five-Year Review		
Each FRCC Regional Reliability Standard shall be reviewed at least once every five (5) years. The review date will be determined from the effective date or the latest revision date whichever is later.	Each FRCC Regional Reliability Standard developed through *FRCC Regional Reliability Standard Development Process* shall be reviewed at	Section was significantly expanded to provide clarifying verbiage in regards to process requirements. Specifically established the ‘review team’ for FRCC Regional Reliability Standards

The review process shall be conducted in accordance with *Steps* 1 through 10 of the *FRCC Regional Reliability Standard* Development Process Manual. As a result of this review, a FRCC Regional Reliability Standard shall be reaffirmed, revised, or withdrawn.	least once every five years from the effective date of the standard. If a FRCC Regional Reliability Standard is nearing its five-year review and has issues that need resolution, then a FRCC Regional Reliability Standard Development project will be initiated for the complete review and associated revision of that standard that includes addressing all outstanding governmental directives and all unresolved issues identified by stakeholders. The standard development project will be processed in accordance with Section III. *Steps in Developing a FRCC Regional Reliability Standard* of this procedure. If a FRCC Regional Reliability Standard is nearing its five-year review and there are no outstanding governmental directives or unresolved stakeholder issues associated with that standard, then a FRCC Regional Reliability Standard Development project will be initiated solely for the "five-year review" of that standard and will be addressed by the following process. For a project that is focused solely on the five-year review, the FRCC RECCF shall appoint a review team of subject matter experts to review the FRCC Regional Reliability Standard and recommend whether the standard should be reaffirmed, revised, or withdrawn. Each review team shall post its recommendations for a thirty (30) calendar day formal stakeholder comment period and shall provide those stakeholder comments to the FRCC RECCF for consideration. If a review team recommends reaffirming a FRCC Regional Reliability Standard, the FRCC RECCF	where there are no outstanding governmental directives or unresolved stakeholder issues associated with that standard, to conduct a review and the associated process to following under these circumstances.

	shall submit the reaffirmation to the FRCC Board of Directors for concurrence. Reaffirmation does not require approval by stakeholder ballot. If a review team recommends modifying or withdrawing a FRCC Regional Reliability Standard, the team shall develop a SAR with such a proposal and the SAR shall be submitted to the FRCC RECCF for acceptance as a new project. Each existing standard recommended for modification or withdrawal shall remain in effect in accordance with the associated implementation plan until the action to modify or withdraw the standard is approved by its ballot pool, adopted by the FRCC Board of Directors, and approved by applicable governmental authorities. In the case of reaffirmation of a FRCC Regional Reliability Standard, the standard shall remain in effect pending the results of the next five-year review or until the standard is otherwise modified or withdrawn by a separate action.	

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)**	**Docket No. _____**

JOINT PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND WESTERN ELECTRICITY COORDINATING COUNCIL FOR APPROVAL OF INTERPRETATION OF REGIONAL RELIABILITY STANDARD BAL-002-WECC-2a

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UNITED STATES OF AMERICA
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JOINT PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND WESTERN ELECTRICITY COORDINATING COUNCIL FOR APPROVAL OF INTERPRETATION OF REGIONAL RELIABILITY STANDARD BAL-002-WECC-2a

Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] and the Western Electricity Coordinating Council ("WECC") hereby submit for Commission approval a proposed interpretation of regional Reliability Standard BAL-002-WECC-2. The proposed interpretation provides clarification, consistent with the Commission's Order No. 789 approving BAL-002-WECC-2,[4] that certain technologies, both contemplated and not yet contemplated, may be used as potential resources to meet the Operating Reserve-Spinning[5] requirement, so long as the resource can meet the response characteristics described in the standard.

NERC and WECC request that the Commission approve proposed regional Reliability Standard BAL-002-WECC-2a (**Exhibit A**), an interpretation of regional Reliability Standard

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1 16 U.S.C. § 824o (2012).

2 18 C.F.R. § 39.5 (2016).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

4 *Regional Reliability Standard BAL-002-WECC-2 – Contingency Reserve*, Order No. 789, 145 FERC ¶ 61,141 (2013) ("Order No. 789").

5 Unless otherwise designated, capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* ("*NERC Glossary of Terms*"), *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf.

BAL-002-WECC-2 – Contingency Reserve, and find that the proposed interpretation is just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC and WECC also request approval of the associated implementation plan (**Exhibit B**).

As required by Section 39.5(a)[6] of the Commission's regulations, this petition presents the technical basis and purpose of proposed regional Reliability Standard BAL-002-WECC-2a and a summary of the interpretation development history. The proposed interpretation was approved by the WECC Board of Directors on June 16, 2016 and was adopted by the NERC Board of Trustees on November 2, 2016.

I. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[7]

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II. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[8] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Bulk Power System,

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6 18 C.F.R. § 39.5(a) (2016).

7 Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2016), to allow the inclusion of more than two persons on the service list in this proceeding.

8 16 U.S.C. § 824o (2012).

and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[9] of the FPA states that all users, owners, and operators of the Bulk Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[10] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[11] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission is vested with the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk Power System and to ensure that Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[12] and Section 39.5(c)[13] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard. Under these same authorities, the Commission will give due weight to the technical expertise of a Regional Entity, like WECC, that is organized on an Interconnection-wide basis with respect to a regional Reliability Standard to be applicable within that Interconnection.

A regional Reliability Standard proposed by a Regional Entity must meet the same standards that NERC's Reliability Standards must meet; i.e., the regional Reliability Standard

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9 *Id.* § 824o(b)(1).

10 *Id.* § 824o(d)(5).

11 18 C.F.R. § 39.5(a) (2016).

12 16 U.S.C. § 824o(d)(2)(2012).

13 18 C.F.R. § 39.5(c)(1)(2016).

must be shown to be just, reasonable, not unduly discriminatory or preferential, and in the public interest.[14] Order No. 672 provides additional criteria that a regional Reliability Standard must satisfy. Specifically, a regional difference from a continent-wide Reliability Standard must either be: (1) more stringent than the continent-wide Reliability Standard (which includes a regional standard that addresses matters that the continent-wide Reliability Standard does not), or (2) necessitated by a physical difference in the Bulk-Power System.[15]

WECC is a Regional Entity organized on an Interconnection-wide basis. WECC regional Reliability Standards are intended to apply only in the Western Interconnection. WECC develops regional Reliability Standards in accordance with its *Reliability Standards Development Procedures* ("RSDP").[16] As discussed in the WECC RSDP, WECC regional Reliability Standards are developed through a transparent, inclusive, open, and balanced process with reasonable notice and opportunity for public comment. Proposed WECC regional Reliability Standards are subject to approval by NERC, as the ERO, and FERC before becoming mandatory and enforceable under Section 215 of the FPA.

B. Interpretation Procedural History

The Commission approved regional Reliability Standard BAL-002-WECC-2 – Contingency Reserve in Order No. 789, issued on November 21, 2013.[17] On March 5, 2015, Arizona Public Service Company ("APS") submitted a Standard Authorization Request -

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[14] 16 U.S.C. § 824o(d)(2) and 18 C.F.R. § 39.5(a).

[15] Order No. 672, *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, FERC Stats. & Regs. ¶ 31,204 at P 291, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[16] The WECC RSDP was approved by the Commission on December 23, 2014 (*see N. Am. Elec. Reliability Corp.*, Docket No. RR14-8-000 (Dec. 23, 2014) (unpublished letter order)) and is available at http://www.nerc.com/FilingsOrders/us/Regional%20Delegation%20Agreements%20DL/WECC_RSDP_20141223.pdf

[17] Order No. 789, *supra* note 4 at 1.

Request for Interpretation of BAL-002-WECC-2. Citing Order No. 789, APS sought clarification that APS and other Balancing Authorities and/or Reserve Sharing Groups "can include 'technologies, such as batteries, both contemplated and not yet contemplated…as potential resources [to meet the Operating Reserve-Spinning requirement of BAL-002-WECC-2, Requirement R2] – so long as the …resource can meet the response characteristics described in the standard." The WECC Standards Committee approved the SAR on March 10, 2015 and a drafting team was appointed.

The proposed interpretation was posted for a 45-day public comment period from May 4, 2015 through June 18, 2015. The ballot for the proposed interpretation ran from July 23, 2015 through August 7, 2015. The proposed interpretation achieved a 73.3% quorum and 100% approval. Pursuant to the NERC Rules of Procedure, the proposed interpretation was posted at NERC for a 45-day public comment period from August 4, 2015 through September 17, 2015. Three sets of supportive responses were received.

The proposed interpretation was approved by the WECC Board of Directors on June 16, 2016 and was adopted by the NERC Board of Trustees on November 2, 2016.

III. JUSTIFICATION FOR APPROVAL

The purpose of the currently-effective continent-wide BAL-002 Disturbance Control Performance Reliability Standard is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. The purpose of regional Reliability Standard BAL-002-WECC-2 — Contingency Reserve is to provide a regional Reliability Standard that specifies the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions.

The proposed interpretation provides clarity regarding the types of resources that may be used to satisfy the Contingency Reserve requirements of BAL-002-WECC-2; specifically, the resources that may qualify as Operating Reserve – Spinning under the standard. As discussed below, the proposed interpretation is consistent with the Commission's Order No. 789 approving the regional standard. NERC and WECC respectfully request that the Commission approve the proposed interpretation as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

A. Order No. 789: Non-Traditional Resources May Qualify as Operating Reserve - Spinning

BAL-002-WECC-2 Requirement R1.2 provides that each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve that is comprised by any combination of a number of reserve types, including Operating Reserve – Spinning. Operating Reserve – Spinning is defined in the *Glossary of Terms Used in NERC Reliability Standards* as follows:

> The portion of Operating Reserve consisting of:
>
> • Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or
>
> • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

BAL-002-WECC-2 Requirement R2 provides that each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve per Requirement R1 as Operating Reserve – Spinning that meets two reserve characteristics: (i) Reserve that is immediately and automatically responsive to frequency

deviations through the action of a governor or other control system; and (ii) Reserve that is capable of fully responding within ten minutes.

Responding to comments submitted by the California Independent System Operator Corporation, the Commission determined in Order No. 789 that non-traditional resources may qualify as "Operating Reserve – Spinning" for purposes of BAL-002-WECC-2 so long as those resources satisfied the technical and performance requirements in Requirement R2. The Commission stated:

> The Commission determines that non-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" provided those resources satisfy the technical and performance requirements in Requirement R2. Our determination is supported by the standard drafting team's response to a comment during the standard drafting process where the standard drafting team stated that "technologies, such as batteries, both contemplated and not yet contemplated are included in the standard as potential resources – so long as the undefined resource can meet the response characteristics described in the standard …The language does not preclude any specific technology; rather, the language delineates how that technology must [] respond." We also note that non-traditional resources could contribute to contingency reserve under the regional Reliability Standard if they are resources, "other than generation or load, that can provide energy or reduce energy consumption." (internal citation omitted).[18]

As discussed below, the Commission's determination in paragraph 48 of Order No. 789 forms the basis for the proposed interpretation.

B. Proposed Interpretation

Regional Reliability Standard BAL-002-WECC-2a adds the following interpretation to Section E of the standard:

> Arizona Public Service (APS) sought clarification that for purposes of BAL-002-WECC-2, Requirement R2, APS and other Balancing Authorities and/or Reserve Sharing Groups can include "technologies, such as batteries, both contemplated and not yet

[18] Order No. 789 at P 48.

contemplated…as potential resources [to meet the Operating Reserve – Spinning requirement of BAL-002-WECC-2, Requirement R2] – so long as the…resource can meet the response characteristics described in the standard."

A standards interpretation team comprised of members of the original BAL drafting team concluded that APS' understanding was correct.

"[N]on-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" so long as they meet the technical and performance requirements in Requirement R2 (i.e., that the resources must be immediately and automatically responsive to frequency deviations through the action of a control system and capable of fully responding within ten minutes).[FN1]

In Order 789, Paragraph 48, the Federal Energy Regulatory Commission (Commission) responded to the California Independent System Operator that:

Commission Determination
48. The Commission determines that non-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" provided those resources satisfy the technical and performance requirements in Requirement R2. Our determination is supported by the standard drafting team's response to a comment during the standard drafting process where the standard drafting team stated that "technologies, such as batteries, both contemplated and not yet contemplated are included in the standard as potential resources – so long as the undefined resource can meet the response characteristics described in the standard …The language does not preclude any specific technology; rather, the language delineates how that technology must [] respond."[FN2] We also note that non-traditional resources could contribute to contingency reserve under the regional Reliability Standard if they are resources, "other than generation or load, that can provide energy or reduce energy consumption."

[FN1]: FERC Order 789, P47. July 18, 2013.
See also FERC Order 740, Section E, Demand-Side Management as a Resource, at P 50: "The Commission clarified that the purpose of this directive was to ensure comparable treatment of demand-side management with conventional generation or any other technology and to allow demand-side management to be considered as a

> resource for contingency reserves on this basis without requiring the use of any particular contingency reserve option."
>
> [FN2]: "Fn 44 Petition, Exhibit C at 20."

The proposed interpretation thus incorporates, into the standard document, the Commission's determination in Order No. 789 that non-traditional resources may qualify as "Operating Reserve – Spinning" provided those resources satisfy the technical and performance requirements in Requirement R2. Inclusion of the proposed interpretation provides clarity to Balancing Authorities and Reserve Sharing Groups in the WECC region regarding the types of resources that may be used to meet the minimum Contingency Reserve requirements of the standard.

IV. EFFECTIVE DATE

NERC and WECC respectfully request that the Commission approve the proposed implementation plan attached to this Petition as **Exhibit B**. NERC and WECC propose that regional Reliability Standard BAL-002-WECC-2a become effective immediately upon regulatory approval.

V. CONCLUSION

For the reasons set forth above, NERC and WECC respectfully request that the Commission:

- approve proposed regional Reliability Standard BAL-002-WECC-2a, an interpretation of BAL-002-WECC-2 – Contingency Reserve, included in **Exhibit A**; and
- approve the implementation plan included in **Exhibit B.**

Respectfully submitted,

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November 9, 2016

Exhibit A

Proposed Regional Reliability Standard BAL-002-WECC-2a

Proposed Regional Reliability Standard BAL-002-WECC-2a

Clean Version

A. Introduction

1. **Title:** **Contingency Reserve**

2. **Number:** BAL-002-WECC-2a

3. **Purpose:** To specify the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions.

4. **Applicability:**

   4.1 Balancing Authority

   4.1.1. The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Reserve Sharing Group, in which case, the Reserve Sharing Group becomes the responsible entity.

   4.2 Reserve Sharing Group

   4.2.1. The Reserve Sharing Group when comprised of a Source Balancing Authority becomes the source Reserve Sharing Group.

   4.2.2. The Reserve Sharing Group when comprised of a Sink Balancing Authority becomes the sink Reserve Sharing Group.

5. **Effective Date:** See Implementation Plan.

B. Requirements and Measures

R1. Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve, that is: [*Violation Risk Factor: High] [Time Horizon: Real-time operations]*

1.1 The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

1.2 Comprised of any combination of the reserve types specified below:

- Operating Reserve – Spinning

- Operating Reserve - Supplemental
- Interchange Transactions designated by the Source Balancing Authority as Operating Reserve – Supplemental
- Reserve held by other entities by agreement that is deliverable on Firm Transmission Service
- A resource, other than generation or load, that can provide energy or reduce energy consumption
- Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement.
- All other load, not identified above, once the Reliability Coordinator has declared an energy emergency alert signifying that firm load interruption is imminent or in progress.

1.3 Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464).

1.4 An amount of capacity from a resource that is deployable within ten minutes.

M1. Each Balancing Authority and each Reserve Sharing Group will have documentation demonstrating its Contingency Reserve was maintained, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Part 1.1

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates its Contingency Reserve was maintained in accordance with the amounts identified in Requirement R1, Part 1.1, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Attachment A is a practical illustration showing how the generation amount may be calculated under Requirement R1.

- Where Dynamic Schedules are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1 may include, but is not limited to, documentation showing a reciprocal acknowledgement as to which entity is carrying the reserves. This transfer may be all or some portion of

the physical generator and is not limited to the entire physical capability of the generator.

- Where Pseudo-Ties are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1, may include, but is not limited to, documentation accounting for the transfers included in the Pseudo-Ties.

Part 1.2

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.2. Evidence may include, but is not limited to, documentation that reserves were comprised of the types listed in Requirement R1, Part 1.2 for purposes of meeting the Contingency Reserve obligation of Requirement R1. Additionally, for purposes of the last bullet of Requirement R1, Part 1.2, evidence of compliance may include, but is not limited to, documentation that the reliability coordinator had issued an energy emergency alert, indicating that firm Load interruption was imminent or was in progress.

Part 1.3

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.3. Evidence of compliance with Requirement R1, Part 1.3 may include, but is not limited to, documentation that Contingency Reserve amounts are based upon load and generating data averaged over each Clock Hour and excludes Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464.

Part 1.4

Evidence of compliance with Requirement R1, Part 1.4 may include, but is not limited to, documentation that the reserves maintained to comply with Requirement R1, Part 1.4 are fully deployable within ten minutes.

R2. Each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve identified in Requirement R1, as Operating Reserve – Spinning that meets both of the following reserve characteristics. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

2.1 Reserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system;

2.2 Reserve that is capable of fully responding within ten minutes.

M2. Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates it maintained at least half of the Contingency Reserve identified in Requirement R1 as Operating Reserve – Spinning, averaged over each Clock Hour, that met both of the reserve characteristics identified in Requirement R2, Part 2.1 and Requirement R2, Part 2.2.

R3. Each Sink Balancing Authority and each sink Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, except within the first sixty minutes following an event requiring the activation of Contingency Reserve. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M3. Each Sink Balancing Authority and each sink Reserve Sharing Group will have dated documentation demonstrating it maintained an amount of Operating Reserve, in addition to the Contingency Reserve identified in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, for the entire period of the transaction, except within the first sixty minutes following an event requiring the activation of Contingency Reserves, in accordance with Requirement 3.

R4. Each Source Balancing Authority and each source Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve amounts identified in Requirement R1, equal to the amount and type of Operating Reserves for any Operating Reserve transactions for which it is the Source Balancing Authority or source Reserve Sharing Group. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M4. Each Source Balancing Authority and each source Reserve Sharing Group will have dated documentation that demonstrates it maintained an amount of additional Operating Reserves identified in Requirement R1, greater than or equal to the amount and type of that identified in Requirement 4, for the entire period of the transaction.

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2 Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3 Evidence Retention

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

Each Balancing Authority and each Reserve Sharing Group shall keep evidence for Requirement R1 through R4 for three years plus calendar current.

1.4. Additional Compliance Information

1.4.1. This Standard shall apply to each Balancing Authority and each Reserve Sharing Group that has registered with WECC as provided in Part 1.4.2 of Section C.

Each Balancing Authority identified in the registration with WECC as provided in Part 1.4.2 of Section C shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

1.4.2. A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to

the WECC: 1) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, 2) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and 3) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

1.4.3. If an agent properly designated in accordance with Part 1.4.2 of Section C identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance: 1) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, 2) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection 1) of this Part 1.4.3 of Section C, and 3) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection 1) of this Part 1.4.3 of Section C (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

1.4.4. If an agent properly designated in accordance with Part 1.4.2 of Section C fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

1.4.5. Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Part 1.4.2 of Section C shall be subject to this Standard on an individual basis.

Table of Compliance Elements

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.
R2	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 100% but greater than or equal to 90% of	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 90% but greater than or	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 80% but greater than or	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 70% of the required

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			the required Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	equal to 80% of the required Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	equal to 70% of the required Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.
R3	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R3.
R4	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operating Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R4.	Operating Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R4.	Operating Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R4.	Operating Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R4.

D. Regional Variances
None.

E. Interpretations

Interpretation Requested

Arizona Public Service (APS) sought clarification that for purposes of BAL-002-WECC-2, Requirement R2, APS and other Balancing Authorities and/or Reserve Sharing Groups can include "technologies, such as batteries, both contemplated and not yet contemplated…as potential resources [to meet the Operating Reserve – Spinning requirement of BAL-002-WECC-2, Requirement R2] – so long as the…resource can meet the response characteristics described in the standard."

A standards interpretation team comprised of members of the original BAL drafting team concluded that APS' understanding was correct.

"[N]on-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" so long as they meet the technical and performance requirements in Requirement R2 (i.e., that the resources must be immediately and automatically responsive to frequency deviations through the action of a control system and capable of fully responding within ten minutes).[1]

[1] FERC Order 789, P47. July 18, 2013.

See also FERC Order 740, Section E, Demand-Side Management as a Resource, at P 50:
"The Commission clarified that the purpose of this directive was to ensure comparable treatment of demand-side management with conventional generation or any other technology and to allow demand-side management

In Order 789, Paragraph 48, the Federal Energy Regulatory Commission (Commission) responded to the California Independent System Operator that:

> **Commission Determination**
>
> 48. The Commission determines that non-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" provided those resources satisfy the technical and performance requirements in Requirement R2. Our determination is supported by the standard drafting team's response to a comment during the standard drafting process where the standard drafting team stated that "technologies, such as batteries, both contemplated and not yet contemplated are included in the standard as potential resources – so long as the undefined resource can meet the response characteristics described in the standard …The language does not preclude any specific technology; rather, the language delineates how that technology must [] respond."[2] We also note that non-traditional resources could contribute to contingency reserve under the regional Reliability Standard if they are resources, "other than generation or load, that can provide energy or reduce energy consumption."

to be considered as a resource for contingency reserves on this basis without requiring the use of any particular contingency reserve option."

[2] "Fn 44 Petition, Exhibit C at 20."

F. Associated Documents
None.

Attachment A

Attachment A is illustrative only; it is not a requirement. Requirement R1 calls for an amount of Contingency Reserve to be maintained, predicated on an amount of generation and load required in Requirement R1, Part 1.1., specifically:

> **"1.1** The greater of either:
>
> - The amount of Contingency Reserve equal to the loss of the most severe single contingency;
> - The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation."

Attachment A illustrates one possible way to account for and calculate the amount of generation upon which the Contingency Reserve amount is predicated.

Below is a practical illustration showing how the generation amount may be calculated under Requirement R1 for Balancing Authorities (BA) and Reserve Sharing Groups (RSG).

BA1 / RSG 1	**Generation**	**Part of Generator**
Generator 1	300 MWs online	Yes
Generator 2	200 MWs online	Yes
Generator 3 (Pseudo-Tied out to BA2)	100 MWs online	No
Generator 4 QF (has backup contract)	10 MWs online	No
Generator 5 QF in EMS	10 MWs online	Yes
Generator 6	0 MWs online	Yes
Dynamic Schedule to BA2 from BA1[3]	(50 MWs)	
Generation	620 MWs	(The sum of gen 1-6)
BA generation (EMS)	510 MWs	(The sum of gen 1, 2, and 5)
Generation to use Under BAL-002-WECC-1	460 MWs**	(The sum of gen 1, 2 and 5 minus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would maintain reserves based on 510 MWs Generation.

BA2 / RSG2	**Generation**	**Part of Generator**
Generator 11	100 MWs	Yes
Generator 12	100 MWs	Yes
Generator 3 (Pseudo-Tied in from BA1)	100 MWs	Yes

[3] Note: This Dynamic Schedule is not the same as the Generator 3 Pseudo-Tie.

Dynamic Schedule from BA1 to BA2	50 MWs	Yes
Generation	300 MWs	(The sum of gen 11, 12 and 3.)
BA generation (EMS)	300 MWs	(The sum of gen 11, 12 and 3)
Generation to use Under BAL-002-WECC-1	350 MWs**	(The sum of gen 11, 12 and 3 plus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would have to maintain reserves based on 510MWs Generation and BA2 would determine its generation to be 300 MWs.

Guideline and Technical Basis

A Guidance Document addressing implementation of this standard has been filed with this standard.

Version History

Version	Date	Action	Change Tracking
1	October 29, 2008	Adopted by NERC Board of Trustees	
1	October 21, 2010	Order issued remanding BAL-002-WECC-1	
2	November 7, 2012	Adopted by NERC Board of Trustees	
2	November 21, 2013	FERC Order issued approving BAL-002-WECC-2. (Order becomes effective 1/28/14.)	
2a	December 1, 2015	Approved by WECC Board of Directors	Clarified resources available for use in Requirement R2
2a	November 2, 2016	Approved by NERC Board of Trustees	

Proposed Regional Reliability Standard BAL-002-WECC-2a

Redline Version

A. Introduction

1. **Title:** **Contingency Reserve**

2. **Number:** BAL-002-WECC-~~2~~2a

3. **Purpose:** To specify the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions.

4. **Applicability:**

   4.1 Balancing Authority

   4.1.1. The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Reserve Sharing Group, in which case, the Reserve Sharing Group becomes the responsible entity.

   4.2 Reserve Sharing Group

   4.2.1. The Reserve Sharing Group when comprised of a Source Balancing Authority becomes the source Reserve Sharing Group.

   4.2.2. The Reserve Sharing Group when comprised of a Sink Balancing Authority becomes the sink Reserve Sharing Group.

5. **Effective Date:** ~~On the first day of the third quarter following applicable regulatory approval~~See Implementation Plan.

B. Requirements and Measures

R1. Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve, that is: [*Violation Risk Factor: High] [Time Horizon: Real-time operations]*

1.1 The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

1.2 Comprised of any combination of the reserve types specified below:

- Operating Reserve – Spinning
- Operating Reserve - Supplemental
- Interchange Transactions designated by the Source Balancing Authority as Operating Reserve – Supplemental
- Reserve held by other entities by agreement that is deliverable on Firm Transmission Service
- A resource, other than generation or load, that can provide energy or reduce energy consumption
- Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement.
- All other load, not identified above, once the Reliability Coordinator has declared an energy emergency alert signifying that firm load interruption is imminent or in progress.

1.3 Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464).

1.4 An amount of capacity from a resource that is deployable within ten minutes.

M1. Each Balancing Authority and each Reserve Sharing Group will have documentation demonstrating its Contingency Reserve was maintained, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Part 1.1

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates its Contingency Reserve was maintained in accordance with the amounts identified in Requirement R1, Part 1.1, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Attachment A is a practical illustration showing how the generation amount may be calculated under Requirement R1.

- Where Dynamic Schedules are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1 may include, but is not limited

to, documentation showing a reciprocal acknowledgement as to which entity is carrying the reserves. This transfer may be all or some portion of the physical generator and is not limited to the entire physical capability of the generator.

- Where Pseudo-Ties are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1, may include, but is not limited to, documentation accounting for the transfers included in the Pseudo-Ties.

Part 1.2

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.2. Evidence may include, but is not limited to, documentation that reserves were comprised of the types listed in Requirement R1, Part 1.2 for purposes of meeting the Contingency Reserve obligation of Requirement R1. Additionally, for purposes of the last bullet of Requirement R1, Part 1.2, evidence of compliance may include, but is not limited to, documentation that the reliability coordinator had issued an energy emergency alert, indicating that firm Load interruption was imminent or was in progress.

Part 1.3

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.3. Evidence of compliance with Requirement R1, Part 1.3 may include, but is not limited to, documentation that Contingency Reserve amounts are based upon load and generating data averaged over each Clock Hour and excludes Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464.

Part 1.4

Evidence of compliance with Requirement R1, Part 1.4 may include, but is not limited to, documentation that the reserves maintained to comply with Requirement R1, Part 1.4 are fully deployable within ten minutes.

R2. Each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve identified in Requirement R1, as Operating Reserve – Spinning that meets both of the following reserve characteristics. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

2.1 Reserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system;

2.2 Reserve that is capable of fully responding within ten minutes.

M2. Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates it maintained at least half of the Contingency Reserve identified in Requirement R1 as Operating Reserve – Spinning, averaged over each Clock Hour, that met both of the reserve characteristics identified in Requirement R2, Part 2.1 and Requirement R2, Part 2.2.

R3. Each Sink Balancing Authority and each sink Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, except within the first sixty minutes following an event requiring the activation of Contingency Reserve. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M3. Each Sink Balancing Authority and each sink Reserve Sharing Group will have dated documentation demonstrating it maintained an amount of Operating Reserve, in addition to the Contingency Reserve identified in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, for the entire period of the transaction, except within the first sixty minutes following an event requiring the activation of Contingency Reserves, in accordance with Requirement 3.

R4. Each Source Balancing Authority and each source Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve amounts identified in Requirement R1, equal to the amount and type of Operating Reserves for any Operating Reserve transactions for which it is the Source Balancing Authority or source Reserve Sharing Group. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M4. Each Source Balancing Authority and each source Reserve Sharing Group will have dated documentation that demonstrates it maintained an amount of additional Operating Reserves identified in Requirement R1, greater than or equal to the amount and type of that identified in Requirement 4, for the entire period of the transaction.

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2 Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3 Evidence Retention

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

Each Balancing Authority and each Reserve Sharing Group shall keep evidence for Requirement R1 through R4 for three years plus calendar current.

1.4. Additional Compliance Information

1.4.1. This Standard shall apply to each Balancing Authority and each Reserve Sharing Group that has registered with WECC as provided in Part 1.4.2 of Section C.

Each Balancing Authority identified in the registration with WECC as provided in Part 1.4.2 of Section C shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

1.4.2. A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC: 1) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, 2) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and 3) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

1.4.3. If an agent properly designated in accordance with Part 1.4.2 of Section C identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance: 1) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, 2) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection 1) of this Part 1.4.3 of Section C, and 3) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection 1) of this Part 1.4.3 of Section C (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

1.4.4. If an agent properly designated in accordance with Part 1.4.2 of Section C fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

1.4.5. Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Part 1.4.2 of Section C shall be subject to this Standard on an individual basis.

Table of Compliance Elements

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.
R2	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 100% but greater than or equal to 90% of the required	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 90% but greater than or equal to 80% of	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 80% but greater than or equal to 70% of	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 70% of the required Operating

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	the required Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	the required Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.
R3	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R3.
R4	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R4.	Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R4.	Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R4.	Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R4.

D. Regional Variances
None.

E. Interpretations
~~None~~

Interpretation Requested

Arizona Public Service (APS) sought clarification that for purposes of BAL-002-WECC-2, Requirement R2, APS and other Balancing Authorities and/or Reserve Sharing Groups can include "technologies, such as batteries, both contemplated and not yet contemplated…as potential resources [to meet the Operating Reserve – Spinning requirement of BAL-002-WECC-2, Requirement R2] – so long as the…resource can meet the response characteristics described in the standard."

A standards interpretation team comprised of members of the original BAL drafting team concluded that APS' understanding was correct.

"[N]on-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" so long as they meet the technical and performance requirements in Requirement R2 (i.e., that the resources must be immediately and automatically responsive to frequency deviations through the action of a control system and capable of fully responding within ten minutes).[1]

[1] FERC Order 789, P47. July 18, 2013.

See also FERC Order 740, Section E, Demand-Side Management as a Resource, at P 50:

In Order 789, Paragraph 48, the Federal Energy Regulatory Commission (Commission) responded to the California Independent System Operator that:

> **Commission Determination**
>
> 48. The Commission determines that non-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" provided those resources satisfy the technical and performance requirements in Requirement R2. Our determination is supported by the standard drafting team's response to a comment during the standard drafting process where the standard drafting team stated that "technologies, such as batteries, both contemplated and not yet contemplated are included in the standard as potential resources – so long as the undefined resource can meet the response characteristics described in the standard …The language does not preclude any specific technology; rather, the language delineates how that technology must [] respond."[2] We also note that non-traditional resources could contribute to contingency reserve under the regional Reliability Standard if they are resources, "other than generation or load, that can provide energy or reduce energy consumption."

"The Commission clarified that the purpose of this directive was to ensure comparable treatment of demand-side management with conventional generation or any other technology and to allow demand-side management to be considered as a resource for contingency reserves on this basis without requiring the use of any particular contingency reserve option."

[2] "Fn 44 Petition, Exhibit C at 20."

F. Associated Documents

None.

Attachment A

Attachment A is illustrative only; it is not a requirement. Requirement R1 calls for an amount of Contingency Reserve to be maintained, predicated on an amount of generation and load required in Requirement R1, Part 1.1., specifically:

> **"1.1** The greater of either:
>
> - The amount of Contingency Reserve equal to the loss of the most severe single contingency;
> - The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation."

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BA1 / RSG 1	**Generation**	**Part of Generator**
Generator 1	300 MWs online	Yes
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Generator 5 QF in EMS	10 MWs online	Yes
Generator 6	0 MWs online	Yes
Dynamic Schedule to BA2 from BA1[3]	(50 MWs)	
Generation	620 MWs	(The sum of gen 1-6)
BA generation (EMS)	510 MWs	(The sum of gen 1, 2, and 5)
Generation to use Under BAL-002-WECC-1	460 MWs**	(The sum of gen 1, 2 and 5 minus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would maintain reserves based on 510 MWs Generation.

BA2 / RSG2	**Generation**	**Part of Generator**

[3] Note: This Dynamic Schedule is not the same as the Generator 3 Pseudo-Tie.

Generator 11	100 MWs	Yes
Generator 12	100 MWs	Yes
Generator 3 (Pseudo-Tied in from BA1)	100 MWs	Yes
Dynamic Schedule from BA1 to BA2	50 MWs	Yes
Generation	300 MWs	(The sum of gen 11, 12 and 3.)
BA generation (EMS)	300 MWs	(The sum of gen 11, 12 and 3)
Generation to use Under BAL-002-WECC-1	350 MWs**	(The sum of gen 11, 12 and 3 plus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would have to maintain reserves based on 510MWs Generation and BA2 would determine its generation to be 300 MWs.

Guideline and Technical Basis

A Guidance Document addressing implementation of this standard has been filed with this standard.

Version History

Version	Date	Action	Change Tracking
1	October 29, 2008	Adopted by NERC Board of Trustees	
1	October 21, 2010	Order issued remanding BAL-002-WECC-1	
2	November 7, 2012	Adopted by NERC Board of Trustees	
2	November 21, 2013	FERC Order issued approving BAL-002-WECC-2. (Order becomes effective 1/28/14.)	
2a	December 1, 2015	Approved by WECC Board of Directors	Clarified resources available for use in Requirement R2
2a	November 2, 2016	Approved by NERC Board of Trustees	

Exhibit B

Implementation Plan

Implementation Plan WECC-0114 BAL-002-WECC-2a Contingency Reserve Request for Interpretation

Standards Authorization Request

WECC-0114 BAL-002-WECC-2a Standard Authorization Request

Approvals Required

- WECC Board of Directors June 16, 2016
- NERC Board of Trustees November 2, 2016
- FERC Pending

Prerequisite Approvals

The project was balloted at WECC from July 23 through August 27, 2015. The WECC Ballot Pool approved the interpretation with a 100% affirmative vote, zero no votes, and three abstentions.

Results of that ballot are included elsewhere in this filing.

On October 29, 2015, the WECC Standards Committee (WSC) approved forwarding the interpretation to the WECC Board of Directors with a request for approval. Subsequent to this decision WECC received a WECC Standards Authorization Request (SAR) to retire Requirement R2 of BAL-002-WECC-2. Due to the nature of this SAR the WSC agreed to hold the request for WECC Board of Directors (Board) approval pending the outcome of the SAR to retire the requirement. The drafting team for the retirement of Requirement 2 project concluded that a field test of at least a year in length should be conducted prior to retirement of the Requirement. Due to the length of the field test the WSC concluded that the interpretation should move forward.

On June 16, 2016, the WECC Board approved the interpretation during the WECC June Board meeting.

Applicable Entities

- Balancing Authority
- Reserve Sharing Group

Conforming Changes to Other Standards

There are no conforming changes to other standards required to immediately implement the interpretation.

Effective Date

The Effective Date is proposed to be immediately upon receipt of regulatory approval.

Justification of Effective Date

On July 18, 2013, FERC issued Order 789 wherein it addressed the use of non-traditional resources for purposes of Operating Reserve – Spinning. This interpretation is in alignment with that earlier Order and should cause no undue surprise for the industry.

Consideration of Early Compliance

See above.

Retirements

There are no retirements required to immediately implement the interpretation.

Exhibit C

Order No. 672 Criteria

Order 672 Criteria WECC-0114 BAL-002-WECC-2a Contingency Reserves Request for Interpretation

The proposed Interpretation of Requirement R2, BAL-002-WECC-2, Contingency Reserve, a Regional Reliability Standard (RRS), does not change or modify the standard in any way. It only interprets Requirement R2 of the document. Each of the following standardized questions was asked and answered when the original underlying RRS was filed and approved. As such, a brief response indicating no changes were made to the FERC-approved RRS has been provided to many of the standardized questions that follow.

NERC is responsible for ensuring that the Reliability Standards, Violation Risk Factors (VRF), Violation Severity Levels (VSL), definitions, Variances, and Interpretations developed by drafting teams are developed in accordance with NERC processes. They must also meet NERC's benchmarks for Reliability Standards, as well as criteria for governmental approval.

In FERC Order No. 672,[1] the Federal Energy Regulatory Commission (FERC) identified a number of criteria that it will use to analyze reliability standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors, and explains how the proposed regional reliability standard has met or exceeded the criteria:

1. **Proposed reliability standards must be designed to achieve a specified reliability goal.**

   The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the Federal Power Act. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection. Order No. 672 at P 321.

   The proposed interpretation does not change the purpose of the FERC-approved RRS.

2. **Proposed reliability standards must contain a technically sound method to achieve the goal.**

   The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic

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[1] http://www.nerc.com/files/final_rule_reliability_Order_672.pdf

for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons. Order No. 672 at P 324.

No Change to the Standard

Pursuant to the WECC Reliability Standards Development Procedures (Procedures), a request for interpretation of a document is limited to clarifying existing requirements in the approved document and may not expand upon a requirement or provide guidance on how to implement a requirement. This interpretation does not change any of the reliability-related substance of the FERC-approved RRS.

Standard Development

This filing of BAL-002-WECC-2a was developed using the NERC and WECC Standards development processes approved by FERC in effect at each point in the process. Among other things, these processes include drafting of the interpretation by a drafting team composed of subject matter experts (SMEs) from the original drafting team; biographies of those SMEs are provided with this filing. These processes also include repeated public iterative comment/response cycles whereby comments are received from the industry and responses to those comments are provided by the drafting team.

Foundation for the Interpretation

The Interpretation is based on FERC Order 789. In Order 789, Paragraph 48, the Federal Energy Regulatory Commission (Commission) responded to the California Independent System Operator that:

Commission Determination

"48. The Commission determines that non-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" provided those resources satisfy the technical and performance requirements in Requirement R2. Our determination is supported by the standard drafting team's response to a comment during the standard drafting process where the standard drafting team stated that "technologies, such as batteries, both contemplated and not yet contemplated are included in the standard as potential resources – so long as the undefined resource can meet the response characteristics described in the standard …The language does not preclude any specific technology; rather, the language

delineates how that technology must [] respond."[2] We also note that non-traditional resources could contribute to contingency reserve under the regional Reliability Standard if they are resources, "other than generation or load, that can provide energy or reduce energy consumption."

3. **Proposed reliability standards must be applicable to users, owners, and operators of the bulk power system, and not others.**

   The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others. Order No. 672 at P 322.

   The proposed interpretation does not change the applicability of the FERC-approved RRS. BAL-002-WECC-2a complies with Order 672 in that it applies only to Balancing Authorities and Reserve Sharing Groups in the Western Interconnection.

4. **Proposed reliability standards must be clear and unambiguous as to what is required and who is required to comply.**

   The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability. Order No. 672 at P 325.

   The proposed interpretation does not change the requirements of the standard or the applicability. It was posted for separate 45-day comment periods at WECC and NERC. There were no negative concerns, no minority positions, and no requests for changes in either posting. When balloted, the Ballot Pool approved the project with a 100 percent weighted sector approval, with zero negative votes and three abstentions.

5. **Proposed reliability standards must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.**

   The proposed interpretation does not change or impact any of the FERC-approved VRFs or VSLs.

6. **Proposed reliability standards must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.**

   There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner. Order No. 672 at P 327.

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[2] "Fn 44 Petition, Exhibit C at 20."

The proposed interpretation does not change any of the Measures in the FERC-approved RRS.

7. **Proposed reliability standards should achieve a reliability goal effectively and efficiently - but does not necessarily have to reflect "best practices" without regard to implementation cost.**

   The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently. Order No. 672 at P 328.

   The proposed interpretation does not change any of the reliability-related substance of the underlying FERC-approved RRS.

8. **Proposed reliability standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect bulk power system reliability.**

   The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability. Order No. 672 at P 329.

   The proposed interpretation does not change any of the reliability-related substance of the underlying FERC-approved RRS.

9. **Proposed reliability standards may consider costs to implement for smaller entities but not at consequence of less than excellence in operating system reliability.**

   A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it. Order No. 672 at P 330.

   The proposed interpretation does not change any of the reliability-related substance of the underlying FERC-approved RRS.

10. **Proposed reliability standards must be designed to apply throughout North America to the maximum extent achievable with a single reliability standard while not favoring one area or approach.**

A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard. Order No. 672 at P 331.

The proposed interpretation does not alter or otherwise change the applicable entities operating within the Western Interconnection that are identified in the FERC-approved RRS.

11. Proposed reliability standards should cause no undue negative effect on competition or restriction of the grid.

As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another. Order No. 672 at P 332

The proposed interpretation is not anticipated to have any negative impact on competition. Rather, due to the clarification provided additional markets may be availed to fulfil the associated reserve requirements.

12. The implementation time for the proposed reliability standards must be reasonable.

In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability. Order No. 672 at P 333

The requested implementation time of immediately upon regulatory approval is reasonable. In light of the earlier July 18, 2013 FERC Order 789, entities may already be implementing the practices clarified in the interpretation.

13. The reliability standard development process must be open and fair.

Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed

Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission. Order No. 672 at P 334

WECC followed the standard development process approved by FERC in effect at the time of each step in the process.

In accordance with the Procedures, effective March 1, 2012, all drafting team meetings are open to the public.

Two drafting team meetings were held. One meeting addressed the issue; one meeting addressed responses to comments.

Notice of the meetings was provided to NERC, posted on the WECC Web site and embedded in the minutes of each meeting. Meeting minutes are posted on the WECC Web site and accessible by the public.

All meetings were supported by a telephone conference bridge associated with an on-line internet visual capability allowing all participants to see the document(s) as they were being developed. Further, this team held an open-mic standards briefing prior to balloting affording the industry an additional opportunity to have its questions addressed.

The proposed interpretation was posted for separate 45-day comment periods at WECC and at NERC. Neither posting resulted in any requests for change.

Comments and their responses are included in this filing and posted on the WECC Web Site at the WECC-0114 Project Page on the Submitted and Review Comments accordion.

14. Proposed reliability standards must balance with other vital public interests.

Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard. Order No. 672 at P 335

WECC is not aware of any other vital public interests. No such balancing concerns were raised or noted.

15. Proposed reliability standards must consider any other relevant factors.

In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed. Order No. 672 at P 323

WECC is not aware of any other relevant factors and none were raised during development.

Exhibit D

Complete Record of Development

Regional Reliability Standards Under Development

Regional Reliability Standards - Under Development				
Standard No.	**Title**	**Regional Status**	**Dates**	**NERC Status**
Western Electricity Coordinating Council (WECC)				
BAL-002-WECC-2a	Contingency Reserve	Standard Interpretation Under Development	08/04/15-09/17/15	Standard w/ Interpretation Clean **(1)** | Redline to Last Approved **(2)** Info **(3)** Unofficial Comment Form (Word) **(4)** Submit Comments Comments Received **(5)**

A. Introduction

1. **Title:** **Contingency Reserve**

2. **Number:** BAL-002-WECC-2a

3. **Purpose:** To specify the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions.

4. **Applicability:**

   4.1 Balancing Authority

   4.1.1. The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Reserve Sharing Group, in which case, the Reserve Sharing Group becomes the responsible entity.

   4.2 Reserve Sharing Group

   4.2.1. The Reserve Sharing Group when comprised of a Source Balancing Authority becomes the source Reserve Sharing Group.

   4.2.2. The Reserve Sharing Group when comprised of a Sink Balancing Authority becomes the sink Reserve Sharing Group.

5. **Effective Date:** On the first day of the third quarter following applicable regulatory approval.

B. Requirements and Measures

R1. Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve, that is: [*Violation Risk Factor: High] [Time Horizon: Real-time operations]*

1.1 The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

1.2 Comprised of any combination of the reserve types specified below:

- Operating Reserve – Spinning
- Operating Reserve - Supplemental
- Interchange Transactions designated by the Source Balancing Authority as Operating Reserve – Supplemental
- Reserve held by other entities by agreement that is deliverable on Firm Transmission Service
- A resource, other than generation or load, that can provide energy or reduce energy consumption
- Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement.
- All other load, not identified above, once the Reliability Coordinator has declared an energy emergency alert signifying that firm load interruption is imminent or in progress.

1.3 Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464).

1.4 An amount of capacity from a resource that is deployable within ten minutes.

M1. Each Balancing Authority and each Reserve Sharing Group will have documentation demonstrating its Contingency Reserve was maintained, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Part 1.1

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates its Contingency Reserve was maintained in accordance with the amounts identified in Requirement R1, Part 1.1, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Attachment A is a practical illustration showing how the generation amount may be calculated under Requirement R1.

- Where Dynamic Schedules are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1 may include, but is not limited

to, documentation showing a reciprocal acknowledgement as to which entity is carrying the reserves. This transfer may be all or some portion of the physical generator and is not limited to the entire physical capability of the generator.

- Where Pseudo-Ties are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1, may include, but is not limited to, documentation accounting for the transfers included in the Pseudo-Ties.

Part 1.2

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.2. Evidence may include, but is not limited to, documentation that reserves were comprised of the types listed in Requirement R1, Part 1.2 for purposes of meeting the Contingency Reserve obligation of Requirement R1. Additionally, for purposes of the last bullet of Requirement R1, Part 1.2, evidence of compliance may include, but is not limited to, documentation that the reliability coordinator had issued an energy emergency alert, indicating that firm Load interruption was imminent or was in progress.

Part 1.3

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.3. Evidence of compliance with Requirement R1, Part 1.3 may include, but is not limited to, documentation that Contingency Reserve amounts are based upon load and generating data averaged over each Clock Hour and excludes Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464.

Part 1.4

Evidence of compliance with Requirement R1, Part 1.4 may include, but is not limited to, documentation that the reserves maintained to comply with Requirement R1, Part 1.4 are fully deployable within ten minutes.

R2. Each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve identified in Requirement R1, as Operating Reserve – Spinning that meets both of the following reserve characteristics. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

2.1 Reserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system;

2.2 Reserve that is capable of fully responding within ten minutes.

M2. Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates it maintained at least half of the Contingency Reserve identified in Requirement R1 as Operating Reserve – Spinning, averaged over each Clock Hour, that met both of the reserve characteristics identified in Requirement R2, Part 2.1 and Requirement R2, Part 2.2.

R3. Each Sink Balancing Authority and each sink Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, except within the first sixty minutes following an event requiring the activation of Contingency Reserve. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M3. Each Sink Balancing Authority and each sink Reserve Sharing Group will have dated documentation demonstrating it maintained an amount of Operating Reserve, in addition to the Contingency Reserve identified in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, for the entire period of the transaction, except within the first sixty minutes following an event requiring the activation of Contingency Reserves, in accordance with Requirement 3.

R4. Each Source Balancing Authority and each source Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve amounts identified in Requirement R1, equal to the amount and type of Operating Reserves for any Operating Reserve transactions for which it is the Source Balancing Authority or source Reserve Sharing Group. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M4. Each Source Balancing Authority and each source Reserve Sharing Group will have dated documentation that demonstrates it maintained an amount of additional Operating Reserves identified in Requirement R1, greater than or equal to the amount and type of that identified in Requirement 4, for the entire period of the transaction.

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2 Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3 Evidence Retention

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

Each Balancing Authority and each Reserve Sharing Group shall keep evidence for Requirement R1 through R4 for three years plus calendar current.

1.4. Additional Compliance Information

1.4.1. This Standard shall apply to each Balancing Authority and each Reserve Sharing Group that has registered with WECC as provided in Part 1.4.2 of Section C.

Each Balancing Authority identified in the registration with WECC as provided in Part 1.4.2 of Section C shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

1.4.2. A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC: 1) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, 2) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and 3) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

1.4.3. If an agent properly designated in accordance with Part 1.4.2 of Section C identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance: 1) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, 2) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection 1) of this Part 1.4.3 of Section C, and 3) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection 1) of this Part 1.4.3 of Section C (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

1.4.4. If an agent properly designated in accordance with Part 1.4.2 of Section C fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

1.4.5. Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Part 1.4.2 of Section C shall be subject to this Standard on an individual basis.

Table of Compliance Elements

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.
R2	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 100% but greater than or equal to 90% of the required	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 90% but greater than or equal to 80% of	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 80% but greater than or equal to 70% of	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 70% of the required Operating

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	the required Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	the required Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.
R3	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R3.
R4	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R4.	Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R4.	Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R4.	Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R4.

D. Regional Variances
None.

E. Interpretations

Interpretation Requested

Arizona Public Service (APS) sought clarification that for purposes of BAL-002-WECC-2, Requirement R2, APS and other Balancing Authorities and/or Reserve Sharing Groups can include "technologies, such as batteries, both contemplated and not yet contemplated…as potential resources [to meet the Operating Reserve – Spinning requirement of BAL-002-WECC-2, Requirement R2] – so long as the…resource can meet the response characteristics described in the standard."

A standards interpretation team comprised of members of the original BAL drafting team concluded that APS' understanding was correct.

"[N]on-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" so long as they meet the technical and performance requirements in Requirement R2 (i.e., that the resources must be immediately and automatically responsive to frequency deviations through the action of a control system and capable of fully responding within ten minutes).[1]

[1] FERC Order 789, P47. July 18, 2013.

See also FERC Order 740, Section E, Demand-Side Management as a Resource, at P 50:
"The Commission clarified that the purpose of this directive was to ensure comparable treatment of demand-side management with conventional generation or any other technology and to allow demand-side management to be considered as a resource for contingency reserves on this basis without requiring the use of any particular contingency reserve option."

In Order 789, Paragraph 48, the Federal Energy Regulatory Commission (Commission) responded to the California Independent System Operator that:

> **Commission Determination**
>
> 48. The Commission determines that non-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" provided those resources satisfy the technical and performance requirements in Requirement R2. Our determination is supported by the standard drafting team's response to a comment during the standard drafting process where the standard drafting team stated that "technologies, such as batteries, both contemplated and not yet contemplated are included in the standard as potential resources – so long as the undefined resource can meet the response characteristics described in the standard …The language does not preclude any specific technology; rather, the language delineates how that technology must [] respond."[2] We also note that non-traditional resources could contribute to contingency reserve under the regional Reliability Standard if they are resources, "other than generation or load, that can provide energy or reduce energy consumption."

[2] "Fn 44 Petition, Exhibit C at 20."

F. Associated Documents
None.

Attachment A

Attachment A is illustrative only; it is not a requirement. Requirement R1 calls for an amount of Contingency Reserve to be maintained, predicated on an amount of generation and load required in Requirement R1, Part 1.1., specifically:

> **"1.1** The greater of either:
>
> - The amount of Contingency Reserve equal to the loss of the most severe single contingency;
> - The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation."

Attachment A illustrates one possible way to account for and calculate the amount of generation upon which the Contingency Reserve amount is predicated.

Below is a practical illustration showing how the generation amount may be calculated under Requirement R1 for Balancing Authorities (BA) and Reserve Sharing Groups (RSG).

BA1 / RSG 1	**Generation**	**Part of Generator**
Generator 1	300 MWs online	Yes
Generator 2	200 MWs online	Yes
Generator 3 (Pseudo-Tied out to BA2)	100 MWs online	No
Generator 4 QF (has backup contract)	10 MWs online	No
Generator 5 QF in EMS	10 MWs online	Yes
Generator 6	0 MWs online	Yes
Dynamic Schedule to BA2 from BA1[3]	(50 MWs)	
Generation	620 MWs	(The sum of gen 1-6)
BA generation (EMS)	510 MWs	(The sum of gen 1, 2, and 5)
Generation to use Under BAL-002-WECC-1	460 MWs**	(The sum of gen 1, 2 and 5 minus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would maintain reserves based on 510 MWs Generation.

BA2 / RSG2	**Generation**	**Part of Generator**
Generator 11	100 MWs	Yes

[3] Note: This Dynamic Schedule is not the same as the Generator 3 Pseudo-Tie.

Generator 12	100 MWs	Yes
Generator 3 (Pseudo-Tied in from BA1)	100 MWs	Yes
Dynamic Schedule from BA1 to BA2	50 MWs	Yes
Generation	300 MWs	(The sum of gen 11, 12 and 3.)
BA generation (EMS)	300 MWs	(The sum of gen 11, 12 and 3)
Generation to use Under BAL-002-WECC-1	350 MWs**	(The sum of gen 11, 12 and 3 plus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would have to maintain reserves based on 510MWs Generation and BA2 would determine its generation to be 300 MWs.

Guideline and Technical Basis

A Guidance Document addressing implementation of this standard has been filed with this standard.

Version History

Version	Date	Action	Change Tracking
1	October 29, 2008	Adopted by NERC Board of Trustees	
1	October 21, 2010	Order issued remanding BAL-002-WECC-1	
2	November 7, 2012	Adopted by NERC Board of Trustees	
2	November 21, 2013	FERC Order issued approving BAL-002-WECC-2. (Order becomes effective 1/28/14.)	

WECC Standard BAL-002-WECC-2a — Contingency Reserve

A. Introduction

1. Title: **Contingency Reserve**

2. Number: BAL-002-WECC-2a

3. Purpose: To specify the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions.

4. Applicability:

4.1 Balancing Authority

4.1.1. The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Reserve Sharing Group, in which case, the Reserve Sharing Group becomes the responsible entity.

4.2 Reserve Sharing Group

4.2.1. The Reserve Sharing Group when comprised of a Source Balancing Authority becomes the source Reserve Sharing Group.

4.2.2. The Reserve Sharing Group when comprised of a Sink Balancing Authority becomes the sink Reserve Sharing Group.

5. Effective Date: ~~October 1, 2014~~ On the first day of the third quarter following applicable regulatory approval.

B. Requirements and Measures

R1. Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve, that is: [*Violation Risk Factor: High] [Time Horizon: Real-time operations]*

1.1 The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

1.2 Comprised of any combination of the reserve types specified below:

- Operating Reserve – Spinning
- Operating Reserve - Supplemental
- Interchange Transactions designated by the Source Balancing Authority as Operating Reserve – Supplemental
- Reserve held by other entities by agreement that is deliverable on Firm Transmission Service
- A resource, other than generation or load, that can provide energy or reduce energy consumption
- Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement.
- All other load, not identified above, once the Reliability Coordinator has declared an energy emergency alert signifying that firm load interruption is imminent or in progress.

1.3 Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464).

1.4 An amount of capacity from a resource that is deployable within ten minutes.

M1. Each Balancing Authority and each Reserve Sharing Group will have documentation demonstrating its Contingency Reserve was maintained, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Part 1.1

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates its Contingency Reserve was maintained in accordance with the amounts identified in Requirement R1, Part 1.1, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Attachment A is a practical illustration showing how the generation amount may be calculated under Requirement R1.

- Where Dynamic Schedules are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1 may include, but is not limited

to, documentation showing a reciprocal acknowledgement as to which entity is carrying the reserves. This transfer may be all or some portion of the physical generator and is not limited to the entire physical capability of the generator.

- Where Pseudo-Ties are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1, may include, but is not limited to, documentation accounting for the transfers included in the Pseudo-Ties.

Part 1.2

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.2. Evidence may include, but is not limited to, documentation that reserves were comprised of the types listed in Requirement R1, Part 1.2 for purposes of meeting the Contingency Reserve obligation of Requirement R1. Additionally, for purposes of the last bullet of Requirement R1, Part 1.2, evidence of compliance may include, but is not limited to, documentation that the reliability coordinator had issued an energy emergency alert, indicating that firm Load interruption was imminent or was in progress.

Part 1.3

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.3. Evidence of compliance with Requirement R1, Part 1.3 may include, but is not limited to, documentation that Contingency Reserve amounts are based upon load and generating data averaged over each Clock Hour and excludes Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464.

Part 1.4

Evidence of compliance with Requirement R1, Part 1.4 may include, but is not limited to, documentation that the reserves maintained to comply with Requirement R1, Part 1.4 are fully deployable within ten minutes.

R2. Each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve identified in Requirement R1, as Operating Reserve – Spinning that meets both of the following reserve characteristics. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

2.1 Reserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system;

2.2 Reserve that is capable of fully responding within ten minutes.

M2. Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates it maintained at least half of the Contingency Reserve identified in Requirement R1 as Operating Reserve – Spinning, averaged over each Clock Hour, that met both of the reserve characteristics identified in Requirement R2, Part 2.1 and Requirement R2, Part 2.2.

R3. Each Sink Balancing Authority and each sink Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, except within the first sixty minutes following an event requiring the activation of Contingency Reserve. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M3. Each Sink Balancing Authority and each sink Reserve Sharing Group will have dated documentation demonstrating it maintained an amount of Operating Reserve, in addition to the Contingency Reserve identified in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, for the entire period of the transaction, except within the first sixty minutes following an event requiring the activation of Contingency Reserves, in accordance with Requirement 3.

R4. Each Source Balancing Authority and each source Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve amounts identified in Requirement R1, equal to the amount and type of Operating Reserves for any Operating Reserve transactions for which it is the Source Balancing Authority or source Reserve Sharing Group. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M4. Each Source Balancing Authority and each source Reserve Sharing Group will have dated documentation that demonstrates it maintained an amount of additional Operating Reserves identified in Requirement R1, greater than or equal to the amount and type of that identified in Requirement 4, for the entire period of the transaction.

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2 Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3 Evidence Retention

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

Each Balancing Authority and each Reserve Sharing Group shall keep evidence for Requirement R1 through R4 for three years plus calendar current.

1.4. Additional Compliance Information

1.4.1. This Standard shall apply to each Balancing Authority and each Reserve Sharing Group that has registered with WECC as provided in Part 1.4.2 of Section C.

Each Balancing Authority identified in the registration with WECC as provided in Part 1.4.2 of Section C shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

1.4.2. A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC: 1) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, 2) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and 3) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

1.4.3. If an agent properly designated in accordance with Part 1.4.2 of Section C identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance: 1) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, 2) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection 1) of this Part 1.4.3 of Section C, and 3) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection 1) of this Part 1.4.3 of Section C (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

1.4.4. If an agent properly designated in accordance with Part 1.4.2 of Section C fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

1.4.5. Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Part 1.4.2 of Section C shall be subject to this Standard on an individual basis.

Table of Compliance Elements

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.
R2	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 100% but greater than or equal to 90% of the required	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 90% but greater than or equal to 80% of	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 80% but greater than or equal to 70% of	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 70% of the required Operating

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	the required Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	the required Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.
R3	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R3.
R4	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating

WECC Standard BAL-002-WECC-2a — Contingency Reserve

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R4.	Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R4.	Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R4.	Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R4.

D. Regional Variances
None.

E. Interpretations

Interpretation Requested

Arizona Public Service (APS) sought clarification that for purposes of BAL-002-WECC-2, Requirement R2, APS and other Balancing Authorities and/or Reserve Sharing Groups can include "technologies, such as batteries, both contemplated and not yet contemplated…as potential resources [to meet the Operating Reserve – Spinning requirement of BAL-002-WECC-2, Requirement R2] – so long as the…resource can meet the response characteristics described in the standard."

A standards interpretation team comprised of members of the original BAL drafting team concluded that APS' understanding was correct.

"[N]on-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" so long as they meet the technical and performance requirements in Requirement R2 (i.e., that the resources must be immediately and automatically responsive to frequency deviations through the action of a control system and capable of fully responding within ten minutes).[1]

[1] FERC Order 789, P47. July 18, 2013.

See also FERC Order 740, Section E, Demand-Side Management as a Resource, at P 50:
"The Commission clarified that the purpose of this directive was to ensure comparable treatment of demand-side management with conventional generation or any other technology and to allow demand-side management to be considered as a resource for contingency reserves on this basis without requiring the use of any particular contingency reserve option."

Deleted: ¶
None.¶
¶

In Order 789, Paragraph 48, the Federal Energy Regulatory Commission (Commission) responded to the California Independent System Operator that:

> **Commission Determination**
>
> 48. The Commission determines that non-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" provided those resources satisfy the technical and performance requirements in Requirement R2. Our determination is supported by the standard drafting team's response to a comment during the standard drafting process where the standard drafting team stated that "technologies, such as batteries, both contemplated and not yet contemplated are included in the standard as potential resources – so long as the undefined resource can meet the response characteristics described in the standard …The language does not preclude any specific technology; rather, the language delineates how that technology must [] respond."[2] We also note that non-traditional resources could contribute to contingency reserve under the regional Reliability Standard if they are resources, "other than generation or load, that can provide energy or reduce energy consumption."

[2] "Fn 44 Petition, Exhibit C at 20."

F. Associated Documents
None.

Attachment A

Attachment A is illustrative only; it is not a requirement. Requirement R1 calls for an amount of Contingency Reserve to be maintained, predicated on an amount of generation and load required in Requirement R1, Part 1.1., specifically:

> **"1.1** The greater of either:
>
> - The amount of Contingency Reserve equal to the loss of the most severe single contingency;
> - The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation."

Attachment A illustrates one possible way to account for and calculate the amount of generation upon which the Contingency Reserve amount is predicated.

Below is a practical illustration showing how the generation amount may be calculated under Requirement R1 for Balancing Authorities (BA) and Reserve Sharing Groups (RSG).

BA1 / RSG 1	**Generation**	**Part of Generator**
Generator 1	300 MWs online	Yes
Generator 2	200 MWs online	Yes
Generator 3 (Pseudo-Tied out to BA2)	100 MWs online	No
Generator 4 QF (has backup contract)	10 MWs online	No
Generator 5 QF in EMS	10 MWs online	Yes
Generator 6	0 MWs online	Yes
Dynamic Schedule to BA2 from BA1[3]	(50 MWs)	
Generation	620 MWs	(The sum of gen 1-6)
BA generation (EMS)	510 MWs	(The sum of gen 1, 2, and 5)
Generation to use Under BAL-002-WECC-1	460 MWs**	(The sum of gen 1, 2 and 5 minus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would maintain reserves based on 510 MWs Generation.

BA2 / RSG2	**Generation**	**Part of Generator**
Generator 11	100 MWs	Yes

[3] Note: This Dynamic Schedule is not the same as the Generator 3 Pseudo-Tie.

Generator 12	100 MWs	Yes
Generator 3 (Pseudo-Tied in from BA1)	100 MWs	Yes
Dynamic Schedule from BA1 to BA2	50 MWs	Yes
Generation	300 MWs	(The sum of gen 11, 12 and 3.)
BA generation (EMS)	300 MWs	(The sum of gen 11, 12 and 3)
Generation to use Under BAL-002-WECC-1	350 MWs**	(The sum of gen 11, 12 and 3 plus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would have to maintain reserves based on 510MWs Generation and BA2 would determine its generation to be 300 MWs.

Guideline and Technical Basis

A Guidance Document addressing implementation of this standard has been filed with this standard.

Version History

Version	Date	Action	Change Tracking
1	October 29, 2008	Adopted by NERC Board of Trustees	
1	October 21, 2010	Order issued remanding BAL-002-WECC-1	
2	November 7, 2012	Adopted by NERC Board of Trustees	
2	November 21, 2013	FERC Order issued approving BAL-002-WECC-2. (Order becomes effective 1/28/14.)	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Regional Reliability Standards Announcement

BAL-002-WECC-2a

Comment Period Open through September 17, 2015

Now Available

Proposed Standard Interpretation for the Western Electricity Coordinating Council (WECC)
WECC has requested NERC to post the regional reliability standard interpretation, **BAL-002-WECC-2a – Contingency Reserve**, for a 45-day comment period.

Commenting

Use the electronic form to submit comments. If you experience any difficulties in using the electronic form, contact Wendy Muller. The form must be completed by **8:00 p.m. Eastern, Thursday, September 17, 2015.** An unofficial Word version of the comment form is posted on the Regional Reliability Standards Under Development page**.**

Regional Reliability Standards Development Process

Section 300 of NERC's Rules of Procedures of the Electric Reliability Organization governs the regional reliability standards development process.

For more information or assistance, contact Reliability Standards Analyst, Mat Bunch (via email) or at (404) 446-9785.

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Regional Reliability Interpretation BAL-002-WECC-2a

DO NOT use this form for submitting comments. Use the electronic form to submit comments on the **Regional Reliability Interpretation for BAL-002-WECC-2a**. The electronic form must be submitted by **8 p.m. Eastern, Thursday, September 17, 2015.**

Documents and information about this project are available on the Regional Reliability Standards Under Development page. If you have questions, contact Mat Bunch or Barb Nutter.

Background Information

A regional reliability standard shall be: (1) a regional reliability standard that is more stringent than the continent-wide reliability standard, including a regional standard that addresses matters that the continent-wide reliability standard does not; or (2) a regional reliability standard that is necessitated by a physical difference in the bulk power system. Regional reliability standards shall provide for as much uniformity as possible with reliability standards across the interconnected bulk power system of the North American continent. Regional reliability standards, when approved by FERC and applicable authorities in Mexico and Canada, shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable bulk power system owners, operators, and users within the applicable area, regardless of membership in the region.

The approval process for a regional reliability standard requires NERC to publicly notice and request comment on the proposed interpretation. Comments shall be permitted only on the following criteria (technical aspects of the standard are vetted through the regional standards development process):

Unfair or Closed Process — The regional reliability interpretation was not developed in a fair and open process that provided an opportunity for all interested parties to participate. Although a NERC-approved regional reliability standards development procedure shall be presumed to be fair and open, objections could be raised regarding the implementation of the procedure.

Adverse Reliability or Commercial Impact on Other Interconnections — The regional reliability interpretation would have a significant adverse impact on reliability or commerce in other interconnections.

Deficient Standard — The regional reliability interpretation fails to provide a level of reliability of the bulk power system such that the regional reliability standard would be likely to cause a serious and substantial threat to public health, safety, welfare, or national security.

Adverse Impact on Competitive Markets within the Interconnection — The regional reliability interpretation would create a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability.

Questions

1. **Do you agree the proposed interpretation was developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?**

   ☐ Yes
   ☐ No
   Comments:

2. **Does the proposed interpretation pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

   ☐ Yes
   ☐ No
   Comments:

3. **Does the proposed interpretation pose a serious and substantial threat to public health, safety, welfare, or national security?**

   ☐ Yes
   ☐ No
   Comments:

4. **Does the proposed interpretation pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?**

   ☐ Yes
   ☐ No
   Comments:

Individual or group. (3 Responses)
Name (1 Responses)
Organization (1 Responses)
Group Name (2 Responses)
Lead Contact (2 Responses)
Question 1 (3 Responses)
Question 1 Comments (3 Responses)
Question 2 (3 Responses)
Question 2 Comments (3 Responses)
Question 3 (3 Responses)
Question 3 Comments (3 Responses)
Question 4 (3 Responses)
Question 4 Comments (3 Responses)

Individual
Arizona Public Service Company
Arizona Public Service Company
Yes
APS fully supports and agrees with the interpretation.
No
No
No
Group
Bonneville Power Administration
Cain Braveheart
Yes
No
No
No
Group
Peak Reliabilitiy

Jared Shakespeare
Yes
Peak supports the interpretation.
No
No
No

Steven L. Rueckert
Western Electricity Coordinating Council
155 North 400 West, Suite 200
Salt Lake City, Utah 84103-1114

September 16, 2016

Subject: Notification of Completion
WECC-0114 BAL-002-WECC-2a Contingency Reserve
Interpretation

To: Mat Bunch
North American Electric Reliability Corporation
3353 Peachtree Rd. NE, North Tower – Suite 600
Atlanta, GA 30326

Dear Mat,

In response to a request from Arizona Public Service Company, and in accordance with the Western Electricity Coordinating Council's (WECC) Reliability Standards Development Procedures (Procedures), the WECC-0114 Interpretation Drafting Team (IDT) has completed its interpretation of BAL-002-WECC-2a Contingency Reserve. The resulting Interpretation has been approved by the WECC Ballot Pool and the WECC Board of Directors (Board).

WECC is seeking adoption of the Interpretation by the NERC Board of Trustees with subsequent petition to the Federal Energy Regulatory Commission (FERC) for final approval.

Overview

Arizona Public Service (APS) sought clarification that for purposes of Requirement R2, APS and other Balancing Authorities and/or Reserve Sharing Groups could include technologies, such as batteries, both contemplated and not yet contemplated, as potential resources to meet the Operating Reserve – Spinning requirement. The IDT concluded it could.

Appendix A is a list of documents provided in support of this project. The actual documents will be forwarded separately. If I may be of further assistance in this filing, please feel free to contact me.

Thank you for your assistance in this matter.

Sincerely,

Steven Rueckert
Director of Standards
Western Electricity Coordinating Council

Appendix A: Supporting Documentation

WECC-0114 BAL-002-WECC-2a Contingency Reserve Request for Interpretation

For documentation support please contact Mr. W. Shannon Black, sblack@wecc.biz, (503) 307-5782.

Regional Reliability Standard Name:	**Contingency Reserves – Interpretation**		
Regional Reliability Standard No:	**BAL-002-WECC-2a**		
	QR	**BOT**	**Gov't Auth.***
SAR – Standard Authorization Request *Attachment A*			
File Name: WECC-0114 BAL-002-WECC-2a Attachment A Request for Intp Standard Authorization Request			
Regional Reliability Standard(s) (clean) *Attachment B*			
File Name: WECC-0114 BAL-002-WECC-2a Attachment B Request for Intp Regional Reliability Standard – Clean			
Regional Reliability Standard(s) (redlined) *Attachment C*			
File Name: WECC-0114 BAL-002-WECC-2a Attachment C Request for Intp Redline to Existing			
Project Roadmap *Attachment D*			
File Name: WECC-0114 BAL-002-WECC-2a Attachment D Request for Intp Project Roadmap			
Implementation Plan *Attachment E*			
File Name: WECC-0114 BAL-002-WECC-2a Attachment E Request for Intp Implementation Plan			
Technical Justification *Attachment F*			
File Name: Not Used			
VRF & VSL Justification *Attachment G*			
File Name: Not Used – no changes to the VRFs and VSLs			
Issue Table and Mapping Document – *Optional Attachment G1*			
File Name: Not Used			
Regional Reliability Standard Submittal Request *Attachment H*			
File Name: WECC-0114 BAL-002-WECC-2a Attachment H Request for Intp Regional Reliability Standard Submittal Request			
Order 672 Criteria *Attachment I*			
File Name: WECC-0114 BAL-002-WECC-2a Attachment I Request for Intp Order 672 Criteria			
Drafting Team Roster with Biographies *Attachment J*			
File Name: WECC-0114 BAL-002-WECC-2a Attachment J Request for Intp Drafting Team Roster with Biographies			
Ballot Pool Members *Attachment K*			
File Name: WECC-0114 BAL-002-WECC-2a Attachment K Request for Intp Ballot Pool Members			
Final Ballot Results *Attachment L*			
File Name: WECC-0114 BAL-002-WECC-2a Attachment L Request for Intp Final Ballot Pool Results			
Guidance Document - *Optional Attachment M*			
File Name: Not Used			

Minority Issues *Attachment N*			
File Name: Not Used. There were none.			
WECC Standards Committee Roster *Attachment O*			
File Name: WECC-0114 BAL-002-WECC-2a Attachment O Request for Intp WECC Standards Committee Roster			
FERC Issues Table *Optional Attachment P*			
File Name: Not Used.			
Additional Supporting Documentation *Attachment Q1 and Q2*			
File Name: Not Used.			
Responses to Comments – WECC *Attachment R1*			
File Name: WECC-0114 BAL-002-WECC-2a Attachment R1 Request for Intp Response to Comments 5-4-2015 through 6-18-2015			
Responses to Comments – NERC *Attachment R2*			
File Name: WECC-0114 BAL-002-WECC-2a Attachment R2 Request for Intp Response to Comments NERC 45 Day Posting			
Petition Filing *(Federal Energy Regulatory Commission)*			
File Name:			
*Applicable governmental authorities in the United States, Canada, and Mexico			
To be provided by NERC.			
The above documents have been provided to NERC in MS Word format.			

Attachment A: Standard Authorization Request
WECC-0114 BAL-002-WECC-2a
Contingency Reserve
Request for Interpretation

Introduction

The SAR is used to propose a new or revised document, to retire an existing document, request interpretation of a document, or request an exemption from a requirement contained in a document. The original SAR is currently located here at the WECC-0114 Project Page on the Standards Authorization Request accordion.

Requester Information

1. Provide your contact information and your alternates contact information:
    - Your First Name: W. Shannon
    - Your Last Name: Black
    - Your Email Address: sblack@wecc.biz
    - Your Phone Number: (503) 307-5782
    - Organization Name: WECC
    - Alternate's First Name: Gary
    - Alternate's Last Name: Nolan
    - Alternate's Email Address: gary.nolan@aps.com
    - Alternate's Phone Number: (602) 250-1135

Type of Request

2. Specify the type of request: (select one)
    - Request for Interpretation

Create, Modify or Retire a Document Questions

Provide the requested information for your request to create, modify, or retire the document.

3. Requested Action: (select one)
    - Other: Interpretation
4. Document Type: (select one)
    - WECC Regional Reliability Standard

5. Issue: Specify what industry problem this request is trying to resolve.

Authority to Seek Interpretation

In accordance with the Reliability Standards Development Procedures, as approved by FERC on December 23, 2014:

"A Request for Interpretation (RI) of a document developed under these Procedures is *limited to clarifying existing requirements* in the approved document and may not expand upon a requirement or provide guidance on how to implement a requirement." (Emphasis added) Step 14 – Submit a Request for Interpretation

Requirement Number and Text Requested for Interpretation:

BAL-002-WECC-2 (BAL), Contingency Reserve, Requirement R2 states:

"R2. Each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve identified in Requirement R1, as *Operating Reserve – Spinning* that meets both of the following reserve characteristics. (Emphasis added)

2.1 Reserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system;

2.2 Reserve that is capable of fully responding within ten minutes."

Analysis

The definition for *Operating Reserve – Spinning* in the NERC Glossary of Terms Used in Reliability Standards is:

"The portion of Operating reserve consisting of:

- Generation synchronized to the system and fully available to serve load within the Disturbance Recovery period following the contingency event; or
- Load fully removable form the system within the Disturbance Recovery Period following the contingency."

In addition to the cited NERC definition, FERC stated in FERC Order 789,

"48. The Commission determines that non-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" provided those resources satisfy the technical and performance requirements in Requirement R2. Our determination is supported by the standard drafting team's response to a comment during the standard drafting process where the standard drafting team stated that "technologies, such as batteries, both contemplated and not yet contemplated are included in the standard as potential resources – so long as the undefined resource can meet the response characteristics described in the standard …The language does not preclude any specific technology; rather, the language

delineates how that technology must [] respond." We also note that non-traditional resources could contribute to contingency reserve under the regional Reliability Standard if they are resources, "other than generation or load, that can provide energy or reduce energy consumption."

If the NERC definition is applied without the benefit of the FERC narrative, only generation synchronized to the grid and Load removable from the grid would be allowed to qualify as Operating Reserve – Spinning. However, when illuminated by the FERC narrative, it appears that the definition is augmented by FERC's position that "technologies, such as batteries, both contemplated and not yet contemplated are included in the standard as potential resources – so long as the undefined resource can meet the response characteristics described in the standard." P. 48 cited above.

Clarification needed:

APS is seeking clarification that for purposes of BAL-002-WECC-2, Requirement R2, APS and other Balancing Authorities and/or Reserve Sharing Groups can include "technologies, such as batteries, both contemplated and not yet contemplated…as potential resources [to meet the Operating Reserve – Spinning requirement of BAL-002-WECC-2, Requirement R2] – so long as the…resource can meet the response characteristics described in the standard."

6. Functions (select all that apply)
   - Balancing Authority
   - Reserve Sharing Groups
7. Affected Reliability Principles: Which of the following reliability principles is MOST affected by this request? (select one)
   - **Reliability Principle 1** — Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Document Information

Specify the documents title, document number, and affected section regarding the request.

8. Document Title: Contingency Reserve
9. Document Number: BAL-002-WECC-2
10. Affected Requirement : Requirement R2

Reference Uploads

Please reference or upload any affected Standards, Regional Business Practices, Criterion, Policies, White Papers, Technical Reports or other relevant documents. If this request is based on a conflict of law, please include a copy of, or accessible reference to, the specific law or regulatory mandate in conflict.

11. Order 742
12. BAL-002-WECC-2, Contingency Reserve

A. Introduction

1. **Title:** **Contingency Reserve**

2. **Number:** BAL-002-WECC-2a

3. **Purpose:** To specify the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions.

4. **Applicability:**

   4.1 Balancing Authority

   4.1.1. The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Reserve Sharing Group, in which case, the Reserve Sharing Group becomes the responsible entity.

   4.2 Reserve Sharing Group

   4.2.1. The Reserve Sharing Group when comprised of a Source Balancing Authority becomes the source Reserve Sharing Group.

   4.2.2. The Reserve Sharing Group when comprised of a Sink Balancing Authority becomes the sink Reserve Sharing Group.

5. **Effective Date:** See Implementation Plan.

B. Requirements and Measures

R1. Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve, that is: [*Violation Risk Factor: High] [Time Horizon: Real-time operations]*

1.1 The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

1.2 Comprised of any combination of the reserve types specified below:

- Operating Reserve – Spinning

- Operating Reserve - Supplemental
- Interchange Transactions designated by the Source Balancing Authority as Operating Reserve – Supplemental
- Reserve held by other entities by agreement that is deliverable on Firm Transmission Service
- A resource, other than generation or load, that can provide energy or reduce energy consumption
- Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement.
- All other load, not identified above, once the Reliability Coordinator has declared an energy emergency alert signifying that firm load interruption is imminent or in progress.

1.3 Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464).

1.4 An amount of capacity from a resource that is deployable within ten minutes.

M1. Each Balancing Authority and each Reserve Sharing Group will have documentation demonstrating its Contingency Reserve was maintained, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Part 1.1

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates its Contingency Reserve was maintained in accordance with the amounts identified in Requirement R1, Part 1.1, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Attachment A is a practical illustration showing how the generation amount may be calculated under Requirement R1.

- Where Dynamic Schedules are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1 may include, but is not limited to, documentation showing a reciprocal acknowledgement as to which entity is carrying the reserves. This transfer may be all or some portion of

the physical generator and is not limited to the entire physical capability of the generator.

- Where Pseudo-Ties are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1, may include, but is not limited to, documentation accounting for the transfers included in the Pseudo-Ties.

Part 1.2

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.2. Evidence may include, but is not limited to, documentation that reserves were comprised of the types listed in Requirement R1, Part 1.2 for purposes of meeting the Contingency Reserve obligation of Requirement R1. Additionally, for purposes of the last bullet of Requirement R1, Part 1.2, evidence of compliance may include, but is not limited to, documentation that the reliability coordinator had issued an energy emergency alert, indicating that firm Load interruption was imminent or was in progress.

Part 1.3

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.3. Evidence of compliance with Requirement R1, Part 1.3 may include, but is not limited to, documentation that Contingency Reserve amounts are based upon load and generating data averaged over each Clock Hour and excludes Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464.

Part 1.4

Evidence of compliance with Requirement R1, Part 1.4 may include, but is not limited to, documentation that the reserves maintained to comply with Requirement R1, Part 1.4 are fully deployable within ten minutes.

R2. Each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve identified in Requirement R1, as Operating Reserve – Spinning that meets both of the following reserve characteristics. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

2.1 Reserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system;

2.2 Reserve that is capable of fully responding within ten minutes.

M2. Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates it maintained at least half of the Contingency Reserve identified in Requirement R1 as Operating Reserve – Spinning, averaged over each Clock Hour, that met both of the reserve characteristics identified in Requirement R2, Part 2.1 and Requirement R2, Part 2.2.

R3. Each Sink Balancing Authority and each sink Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, except within the first sixty minutes following an event requiring the activation of Contingency Reserve. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M3. Each Sink Balancing Authority and each sink Reserve Sharing Group will have dated documentation demonstrating it maintained an amount of Operating Reserve, in addition to the Contingency Reserve identified in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, for the entire period of the transaction, except within the first sixty minutes following an event requiring the activation of Contingency Reserves, in accordance with Requirement 3.

R4. Each Source Balancing Authority and each source Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve amounts identified in Requirement R1, equal to the amount and type of Operating Reserves for any Operating Reserve transactions for which it is the Source Balancing Authority or source Reserve Sharing Group. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M4. Each Source Balancing Authority and each source Reserve Sharing Group will have dated documentation that demonstrates it maintained an amount of additional Operating Reserves identified in Requirement R1, greater than or equal to the amount and type of that identified in Requirement 4, for the entire period of the transaction.

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2 Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3 Evidence Retention

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

Each Balancing Authority and each Reserve Sharing Group shall keep evidence for Requirement R1 through R4 for three years plus calendar current.

1.4. Additional Compliance Information

1.4.1. This Standard shall apply to each Balancing Authority and each Reserve Sharing Group that has registered with WECC as provided in Part 1.4.2 of Section C.

Each Balancing Authority identified in the registration with WECC as provided in Part 1.4.2 of Section C shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

1.4.2. A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to

the WECC: 1) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, 2) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and 3) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

1.4.3. If an agent properly designated in accordance with Part 1.4.2 of Section C identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance: 1) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, 2) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection 1) of this Part 1.4.3 of Section C, and 3) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection 1) of this Part 1.4.3 of Section C (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

1.4.4. If an agent properly designated in accordance with Part 1.4.2 of Section C fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

1.4.5. Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Part 1.4.2 of Section C shall be subject to this Standard on an individual basis.

Table of Compliance Elements

R	Time	VRF	Violation Severity Levels

	Horizon		Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.
R2	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 100% but greater than or equal to 90% of the required Operating Reserve– Spinning amount specified in Requirement R2,	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 90% but greater than or equal to 80% of the required Operating Reserve– Spinning amount	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 80% but greater than or equal to 70% of the required Operating Reserve– Spinning amount	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 70% of the required Operating Reserve– Spinning amount specified in Requirement

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			and both characteristics were met.	specified in Requirement R2, and both characteristics were met.	specified in Requirement R2, and both characteristics were met.	R2, and both characteristics were met.
R3	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R3.
R4	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating Reserve is less than 100% but greater than or equal to 90% of the required	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating Reserve is less than 90% but greater than or equal to 80% of the required	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating Reserve is less than 80% but greater than or equal to 70% of the required	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating Reserve is less than 70% of the required Operating Reserve

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operating Reserve amount specified in Requirement R4.	Operating Reserve amount specified in Requirement R4.	Operating Reserve amount specified in Requirement R4.	amount specified in Requirement R4.

D. Regional Variances
None.

E. Interpretations

Interpretation Requested

Arizona Public Service (APS) sought clarification that for purposes of BAL-002-WECC-2, Requirement R2, APS and other Balancing Authorities and/or Reserve Sharing Groups can include "technologies, such as batteries, both contemplated and not yet contemplated…as potential resources [to meet the Operating Reserve – Spinning requirement of BAL-002-WECC-2, Requirement R2] – so long as the…resource can meet the response characteristics described in the standard."

A standards interpretation team comprised of members of the original BAL drafting team concluded that APS' understanding was correct.

"[N]on-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" so long as they meet the technical and performance requirements in Requirement R2 (i.e., that the resources must be immediately and automatically responsive to frequency deviations through the action of a control system and capable of fully responding within ten minutes).[1]
In Order 789, Paragraph 48, the Federal Energy Regulatory Commission (Commission) responded to the California Independent System Operator that:

Commission Determination

[1] FERC Order 789, P47. July 18, 2013.

See also FERC Order 740, Section E, Demand-Side Management as a Resource, at P 50:
"The Commission clarified that the purpose of this directive was to ensure comparable treatment of demand-side management with conventional generation or any other technology and to allow demand-side management to be considered as a resource for contingency reserves on this basis without requiring the use of any particular contingency reserve option."

48. The Commission determines that non-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" provided those resources satisfy the technical and performance requirements in Requirement R2. Our determination is supported by the standard drafting team's response to a comment during the standard drafting process where the standard drafting team stated that "technologies, such as batteries, both contemplated and not yet contemplated are included in the standard as potential resources – so long as the undefined resource can meet the response characteristics described in the standard …The language does not preclude any specific technology; rather, the language delineates how that technology must [] respond."[2] We also note that non-traditional resources could contribute to contingency reserve under the regional Reliability Standard if they are resources, "other than generation or load, that can provide energy or reduce energy consumption."

[2] "Fn 44 Petition, Exhibit C at 20."

F. Associated Documents
None.

Attachment A

Attachment A is illustrative only; it is not a requirement. Requirement R1 calls for an amount of Contingency Reserve to be maintained, predicated on an amount of generation and load required in Requirement R1, Part 1.1., specifically:

> **"1.1** The greater of either:
>
> - The amount of Contingency Reserve equal to the loss of the most severe single contingency;
> - The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation."

Attachment A illustrates one possible way to account for and calculate the amount of generation upon which the Contingency Reserve amount is predicated.

Below is a practical illustration showing how the generation amount may be calculated under Requirement R1 for Balancing Authorities (BA) and Reserve Sharing Groups (RSG).

BA1 / RSG 1	**Generation**	**Part of Generator**
Generator 1	300 MWs online	Yes
Generator 2	200 MWs online	Yes
Generator 3 (Pseudo-Tied out to BA2)	100 MWs online	No
Generator 4 QF (has backup contract)	10 MWs online	No
Generator 5 QF in EMS	10 MWs online	Yes
Generator 6	0 MWs online	Yes
Dynamic Schedule to BA2 from BA1[3]	(50 MWs)	
Generation	620 MWs	(The sum of gen 1-6)
BA generation (EMS)	510 MWs	(The sum of gen 1, 2, and 5)
Generation to use Under BAL-002-WECC-1	460 MWs**	(The sum of gen 1, 2 and 5 minus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would maintain reserves based on 510 MWs Generation.

BA2 / RSG2	**Generation**	**Part of Generator**
Generator 11	100 MWs	Yes
Generator 12	100 MWs	Yes
Generator 3 (Pseudo-Tied in from BA1)	100 MWs	Yes

[3] Note: This Dynamic Schedule is not the same as the Generator 3 Pseudo-Tie.

Dynamic Schedule from BA1 to BA2	50 MWs	Yes
Generation	300 MWs	(The sum of gen 11, 12 and 3.)
BA generation (EMS)	300 MWs	(The sum of gen 11, 12 and 3)
Generation to use Under BAL-002-WECC-1	350 MWs**	(The sum of gen 11, 12 and 3 plus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would have to maintain reserves based on 510MWs Generation and BA2 would determine its generation to be 300 MWs.

Guideline and Technical Basis

A Guidance Document addressing implementation of this standard has been filed with this standard.

Version History

Version	Date	Action	Change Tracking
1	October 29, 2008	Adopted by NERC Board of Trustees	
1	October 21, 2010	Order issued remanding BAL-002-WECC-1	
2	November 7, 2012	Adopted by NERC Board of Trustees	
2	November 21, 2013	FERC Order issued approving BAL-002-WECC-2. (Order becomes effective 1/28/14.)	
2a	December 1, 2015	Approved by WECC Board of Directors	Clarified resources available for use in Requirement R2
2a	Pending	Approved by NERC Board of Trustees	Clarified resources available for use in Requirement R2

A. Introduction

1. **Title:** **Contingency Reserve**

2. **Number:** BAL-002-WECC-~~2~~2a

3. **Purpose:** To specify the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions.

4. **Applicability:**

   4.1 Balancing Authority

   4.1.1. The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Reserve Sharing Group, in which case, the Reserve Sharing Group becomes the responsible entity.

   4.2 Reserve Sharing Group

   4.2.1. The Reserve Sharing Group when comprised of a Source Balancing Authority becomes the source Reserve Sharing Group.

   4.2.2. The Reserve Sharing Group when comprised of a Sink Balancing Authority becomes the sink Reserve Sharing Group.

5. **Effective Date:** ~~On the first day of the third quarter following applicable regulatory approval~~See Implementation Plan.

B. Requirements and Measures

R1. Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve, that is: [*Violation Risk Factor: High] [Time Horizon: Real-time operations]*

1.1 The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

1.2 Comprised of any combination of the reserve types specified below:

- Operating Reserve – Spinning
- Operating Reserve - Supplemental
- Interchange Transactions designated by the Source Balancing Authority as Operating Reserve – Supplemental
- Reserve held by other entities by agreement that is deliverable on Firm Transmission Service
- A resource, other than generation or load, that can provide energy or reduce energy consumption
- Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement.
- All other load, not identified above, once the Reliability Coordinator has declared an energy emergency alert signifying that firm load interruption is imminent or in progress.

1.3 Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464).

1.4 An amount of capacity from a resource that is deployable within ten minutes.

M1. Each Balancing Authority and each Reserve Sharing Group will have documentation demonstrating its Contingency Reserve was maintained, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Part 1.1

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates its Contingency Reserve was maintained in accordance with the amounts identified in Requirement R1, Part 1.1, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Attachment A is a practical illustration showing how the generation amount may be calculated under Requirement R1.

- Where Dynamic Schedules are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1 may include, but is not limited

to, documentation showing a reciprocal acknowledgement as to which entity is carrying the reserves. This transfer may be all or some portion of the physical generator and is not limited to the entire physical capability of the generator.

- Where Pseudo-Ties are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1, may include, but is not limited to, documentation accounting for the transfers included in the Pseudo-Ties.

Part 1.2

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.2. Evidence may include, but is not limited to, documentation that reserves were comprised of the types listed in Requirement R1, Part 1.2 for purposes of meeting the Contingency Reserve obligation of Requirement R1. Additionally, for purposes of the last bullet of Requirement R1, Part 1.2, evidence of compliance may include, but is not limited to, documentation that the reliability coordinator had issued an energy emergency alert, indicating that firm Load interruption was imminent or was in progress.

Part 1.3

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.3. Evidence of compliance with Requirement R1, Part 1.3 may include, but is not limited to, documentation that Contingency Reserve amounts are based upon load and generating data averaged over each Clock Hour and excludes Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464.

Part 1.4

Evidence of compliance with Requirement R1, Part 1.4 may include, but is not limited to, documentation that the reserves maintained to comply with Requirement R1, Part 1.4 are fully deployable within ten minutes.

R2. Each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve identified in Requirement R1, as Operating Reserve – Spinning that meets both of the following reserve characteristics. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

2.1 Reserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system;

2.2 Reserve that is capable of fully responding within ten minutes.

M2. Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates it maintained at least half of the Contingency Reserve identified in Requirement R1 as Operating Reserve – Spinning, averaged over each Clock Hour, that met both of the reserve characteristics identified in Requirement R2, Part 2.1 and Requirement R2, Part 2.2.

R3. Each Sink Balancing Authority and each sink Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, except within the first sixty minutes following an event requiring the activation of Contingency Reserve. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M3. Each Sink Balancing Authority and each sink Reserve Sharing Group will have dated documentation demonstrating it maintained an amount of Operating Reserve, in addition to the Contingency Reserve identified in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, for the entire period of the transaction, except within the first sixty minutes following an event requiring the activation of Contingency Reserves, in accordance with Requirement 3.

R4. Each Source Balancing Authority and each source Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve amounts identified in Requirement R1, equal to the amount and type of Operating Reserves for any Operating Reserve transactions for which it is the Source Balancing Authority or source Reserve Sharing Group. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M4. Each Source Balancing Authority and each source Reserve Sharing Group will have dated documentation that demonstrates it maintained an amount of additional Operating Reserves identified in Requirement R1, greater than or equal to the amount and type of that identified in Requirement 4, for the entire period of the transaction.

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2 Compliance Monitoring and Assessment Processes:

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Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3 Evidence Retention

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

Each Balancing Authority and each Reserve Sharing Group shall keep evidence for Requirement R1 through R4 for three years plus calendar current.

1.4. Additional Compliance Information

1.4.1. This Standard shall apply to each Balancing Authority and each Reserve Sharing Group that has registered with WECC as provided in Part 1.4.2 of Section C.

Each Balancing Authority identified in the registration with WECC as provided in Part 1.4.2 of Section C shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

1.4.2. A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC: 1) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, 2) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and 3) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

1.4.3. If an agent properly designated in accordance with Part 1.4.2 of Section C identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance: 1) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, 2) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection 1) of this Part 1.4.3 of Section C, and 3) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection 1) of this Part 1.4.3 of Section C (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

1.4.4. If an agent properly designated in accordance with Part 1.4.2 of Section C fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

1.4.5. Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Part 1.4.2 of Section C shall be subject to this Standard on an individual basis.

Table of Compliance Elements

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.
R2	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 100% but greater than or equal to 90% of the required	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 90% but greater than or equal to 80% of	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 80% but greater than or equal to 70% of	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 70% of the required Operating

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	the required Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	the required Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.
R3	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R3.
R4	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve Operating

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R4.	Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R4.	Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R4.	Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R4.

D. Regional Variances
None.

E. Interpretations
~~None~~

Interpretation Requested

Arizona Public Service (APS) sought clarification that for purposes of BAL-002-WECC-2, Requirement R2, APS and other Balancing Authorities and/or Reserve Sharing Groups can include "technologies, such as batteries, both contemplated and not yet contemplated…as potential resources [to meet the Operating Reserve – Spinning requirement of BAL-002-WECC-2, Requirement R2] – so long as the…resource can meet the response characteristics described in the standard."

A standards interpretation team comprised of members of the original BAL drafting team concluded that APS' understanding was correct.

"[N]on-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" so long as they meet the technical and performance requirements in Requirement R2 (i.e., that the resources must be immediately and automatically responsive to frequency deviations through the action of a control system and capable of fully responding within ten minutes).[1]

[1] FERC Order 789, P47. July 18, 2013.

See also FERC Order 740, Section E, Demand-Side Management as a Resource, at P 50:

In Order 789, Paragraph 48, the Federal Energy Regulatory Commission (Commission) responded to the California Independent System Operator that:

> **Commission Determination**
>
> 48. The Commission determines that non-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" provided those resources satisfy the technical and performance requirements in Requirement R2. Our determination is supported by the standard drafting team's response to a comment during the standard drafting process where the standard drafting team stated that "technologies, such as batteries, both contemplated and not yet contemplated are included in the standard as potential resources – so long as the undefined resource can meet the response characteristics described in the standard …The language does not preclude any specific technology; rather, the language delineates how that technology must [] respond."[2] We also note that non-traditional resources could contribute to contingency reserve under the regional Reliability Standard if they are resources, "other than generation or load, that can provide energy or reduce energy consumption."

"The Commission clarified that the purpose of this directive was to ensure comparable treatment of demand-side management with conventional generation or any other technology and to allow demand-side management to be considered as a resource for contingency reserves on this basis without requiring the use of any particular contingency reserve option."

[2] "Fn 44 Petition, Exhibit C at 20."

F. Associated Documents

None.

Attachment A

Attachment A is illustrative only; it is not a requirement. Requirement R1 calls for an amount of Contingency Reserve to be maintained, predicated on an amount of generation and load required in Requirement R1, Part 1.1., specifically:

> **"1.1** The greater of either:
>
> - The amount of Contingency Reserve equal to the loss of the most severe single contingency;
> - The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation."

Attachment A illustrates one possible way to account for and calculate the amount of generation upon which the Contingency Reserve amount is predicated.

Below is a practical illustration showing how the generation amount may be calculated under Requirement R1 for Balancing Authorities (BA) and Reserve Sharing Groups (RSG).

BA1 / RSG 1	**Generation**	**Part of Generator**
Generator 1	300 MWs online	Yes
Generator 2	200 MWs online	Yes
Generator 3 (Pseudo-Tied out to BA2)	100 MWs online	No
Generator 4 QF (has backup contract)	10 MWs online	No
Generator 5 QF in EMS	10 MWs online	Yes
Generator 6	0 MWs online	Yes
Dynamic Schedule to BA2 from BA1[3]	(50 MWs)	
Generation	620 MWs	(The sum of gen 1-6)
BA generation (EMS)	510 MWs	(The sum of gen 1, 2, and 5)
Generation to use Under BAL-002-WECC-1	460 MWs**	(The sum of gen 1, 2 and 5 minus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would maintain reserves based on 510 MWs Generation.

BA2 / RSG2	**Generation**	**Part of Generator**

[3] Note: This Dynamic Schedule is not the same as the Generator 3 Pseudo-Tie.

Generator 11	100 MWs	Yes
Generator 12	100 MWs	Yes
Generator 3 (Pseudo-Tied in from BA1)	100 MWs	Yes
Dynamic Schedule from BA1 to BA2	50 MWs	Yes
Generation	300 MWs	(The sum of gen 11, 12 and 3.)
BA generation (EMS)	300 MWs	(The sum of gen 11, 12 and 3)
Generation to use Under BAL-002-WECC-1	350 MWs**	(The sum of gen 11, 12 and 3 plus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would have to maintain reserves based on 510MWs Generation and BA2 would determine its generation to be 300 MWs.

Guideline and Technical Basis

A Guidance Document addressing implementation of this standard has been filed with this standard.

Version History

Version	Date	Action	Change Tracking
1	October 29, 2008	Adopted by NERC Board of Trustees	
1	October 21, 2010	Order issued remanding BAL-002-WECC-1	
2	November 7, 2012	Adopted by NERC Board of Trustees	
2	November 21, 2013	FERC Order issued approving BAL-002-WECC-2. (Order becomes effective 1/28/14.)	
2a	December 1, 2015	Approved by WECC Board of Directors	Clarified resources available for use in Requirement R2
2a	Pending	Approved by NERC Board of Trustees	Clarified resources available for use in Requirement R2

Project Roadmap

Actions	Proposed Date
1. SAR Filed	3-5-2015
2. WSC approved the SAR	3-10-2015
3. WSC assigned original BAL DT, as available	3-10-2015
4. First DT meeting	4-30-2015
5. Posting 1 Comments Open	5-4-2015
6. Posting 1 Comments Closed (45-day)	6-18-2015
7. DT Meets to answer Comments	6-19-2015
8. WSC approves for Ballot	6-23-2015
9. Notice of Ballot Pool Forming	6-29-2015
10. Notice of Standards Briefing	7-6-2015
11. Ballot Pool – Open	7-7-2015
12. Ballot Pool – Closed	7-21-2015
13. Standards Briefing	7-22-2015
14. Ballot Open	7-23-2015
15. NERC Posting for 45 days – Open	8-4-2015
16. Ballot Closes	8-7-2015
17. NERC Posting for 45 days – Closed[1]	9-17-2015
18. WSC approves forwarding document to the WECC Board of	10-29-2015

[1] As no comments were received to address no further DT meetings were held.

Directors / Standards Documents to Admin	
19. WECC Board of Directors approval	6-16-2016
20. NERC Board of Trustees adoption	Pending
21. FERC approval	Pending

Attachment E: Implementation Plan
WECC-0114 BAL-002-WECC-2a
Contingency Reserve
Request for Interpretation

Standards Authorization Request

WECC-0114 BAL-002-WECC-2a Standard Authorization Request

Approvals Required

- WECC Board of Directors June 16, 2016
- NERC Board of Trustees Pending
- FERC Pending

Prerequisite Approvals

The project was balloted at WECC from July 23 through August 27, 2015. The WECC Ballot Pool approved the interpretation with a 100% affirmative vote, zero no votes, and three abstentions.

Results of that ballot are included elsewhere in this filing.

On October 29, 2015, the WECC Standards Committee (WSC) approved forwarding the interpretation to the WECC Board of Directors with a request for approval. Subsequent to this decision WECC received a WECC Standards Authorization Request (SAR) to retire Requirement R2 of BAL-002-WECC-2. Due to the nature of this SAR the WSC agreed to hold the request for WECC Board of Directors (Board) approval pending the outcome of the SAR to retire the requirement. The drafting team for the retirement of Requirement 2 project concluded that a field test of at least a year in length should be conducted prior to retirement of the Requirement. Due to the length of the field test the WSC concluded that the interpretation should move forward.

On June 16, 2016, the WECC Board approved the interpretation during the WECC June Board meeting.

Applicable Entities

- Balancing Authority
- Reserve Sharing Group

Conforming Changes to Other Standards

There are no conforming changes to other standards required to immediately implement the interpretation.

Effective Date

The Effective Date is proposed to be immediately upon receipt of regulatory approval.

Justification of Effective Date

On July 18, 2013, FERC issued Order 789 wherein it addressed the use of non-traditional resources for purposes of Operating Reserve – Spinning. This interpretation is in alignment with that earlier Order and should cause no undue surprise for the industry.

Consideration of Early Compliance

See above.

Retirements

There are no retirements required to immediately implement the interpretation.

Regional Reliability Standard Submittal Request
Attachment H

Region:	**Western Electricity Coordinating Council**
Regional Standard Number:	**BAL-002-WECC-2a**
Regional Standard Title:	**Contingency Reserves – Interpretation**
Date Submitted:	**September 16, 2016**
Regional Contact Name:	**Steven Rueckert**
Regional Contact Title:	**Director of Standards**
Regional Contact Telephone Number:	**(801) 883-6878**

Request (check all that apply):

- ☒ Interpret an Existing Standard
- ☐ Approval of a new standard
- ☐ Revision of an existing standard
- ☐ Withdrawal of an existing standard
- ☐ Urgent Action

Has this action been approved by your Board of Directors:

- ☒ Yes – June 16, 2016
- ☐ No

(If no please indicate date standard action is expected along with the current status (e.g., third comment period with anticipated board approval on mm/dd/year)):

The WECC Board of Directors approved the following resolution on June 16, 2016.

A. *Resolved*, that the Western Electricity Coordinating Council (WECC) Board of Directors (Board), acting on the recommendation of the WECC Standards Committee (WSC) at the meeting of the Board on June 16, 2016, hereby approves the interpretation of BAL-002-WECC-2, Contingency Reserve, Requirement R2 as attached hereto.

[Note: The purpose of the remaining questions is to provide NERC with the information needed to file the regional standard(s) with FERC. The information provided may to a large degree be used verbatim. It is extremely important for the entity submitting this form to provide sufficient detail that clearly delineates the scope and justification of the request.]

Concise statement of the basis and purpose (scope) of request:	Arizona Public Service (APS) is seeking clarification that for purposes of BAL-002-WECC-2, Requirement R2, APS and other Balancing Authorities and/or Reserve Sharing Groups can include "technologies, such as batteries, both contemplated and not yet contemplated…as potential resources [to meet the Operating Reserve – Spinning requirement of BAL-002-WECC-2, Requirement R2] – so long as the…resource can meet the response characteristics described in the standard."
Concise statement of the justification of the request:	Pursuant to WECC's Reliability Standards Development Procedures (Procedures), a request for interpretation of a document developed under the Procedures is limited to clarifying existing requirements in the approved document and may not expand upon a requirement or provide guidance on how to implement a requirement. APS seeks clarification that it can use non-traditional resources for purposes of meeting BAL-002-WECC-2a, Contingency Reserves. Basing its conclusion on FERC Order 789, the Interpretation Drafting Team concurred that non-traditional resources could be used.

Attachment I: Order 672 Criteria
WECC-0114 BAL-002-WECC-2a Contingency Reserves Request for Interpretation

The proposed Interpretation of Requirement R2, BAL-002-WECC-2, Contingency Reserve, a Regional Reliability Standard (RRS), does not change or modify the standard in any way. It only interprets Requirement R2 of the document. Each of the following standardized questions was asked and answered when the original underlying RRS was filed and approved. As such, a brief response indicating no changes were made to the FERC-approved RRS has been provided to many of the standardized questions that follow.

NERC is responsible for ensuring that the Reliability Standards, Violation Risk Factors (VRF), Violation Severity Levels (VSL), definitions, Variances, and Interpretations developed by drafting teams are developed in accordance with NERC processes. They must also meet NERC's benchmarks for Reliability Standards, as well as criteria for governmental approval.

In FERC Order No. 672,[1] the Federal Energy Regulatory Commission (FERC) identified a number of criteria that it will use to analyze reliability standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors, and explains how the proposed regional reliability standard has met or exceeded the criteria:

1. **Proposed reliability standards must be designed to achieve a specified reliability goal.**

   The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the Federal Power Act. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection. Order No. 672 at P 321.

   The proposed interpretation does not change the purpose of the FERC-approved RRS.

2. **Proposed reliability standards must contain a technically sound method to achieve the goal.**

   The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic

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[1] http://www.nerc.com/files/final_rule_reliability_Order_672.pdf

for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons. Order No. 672 at P 324.

No Change to the Standard

Pursuant to the WECC Reliability Standards Development Procedures (Procedures), a request for interpretation of a document is limited to clarifying existing requirements in the approved document and may not expand upon a requirement or provide guidance on how to implement a requirement. This interpretation does not change any of the reliability-related substance of the FERC-approved RRS.

Standard Development

This filing of BAL-002-WECC-2a was developed using the NERC and WECC Standards development processes approved by FERC in effect at each point in the process. Among other things, these processes include drafting of the interpretation by a drafting team composed of subject matter experts (SMEs) from the original drafting team; biographies of those SMEs are provided with this filing. These processes also include repeated public iterative comment/response cycles whereby comments are received from the industry and responses to those comments are provided by the drafting team.

Foundation for the Interpretation

The Interpretation is based on FERC Order 789. In Order 789, Paragraph 48, the Federal Energy Regulatory Commission (Commission) responded to the California Independent System Operator that:

Commission Determination

"48. The Commission determines that non-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" provided those resources satisfy the technical and performance requirements in Requirement R2. Our determination is supported by the standard drafting team's response to a comment during the standard drafting process where the standard drafting team stated that "technologies, such as batteries, both contemplated and not yet contemplated are included in the standard as potential resources – so long as the undefined resource can meet the response characteristics described in the standard …The language does not preclude any specific technology; rather, the language

delineates how that technology must [] respond."[2] We also note that non-traditional resources could contribute to contingency reserve under the regional Reliability Standard if they are resources, "other than generation or load, that can provide energy or reduce energy consumption."[SR1]

3. **Proposed reliability standards must be applicable to users, owners, and operators of the bulk power system, and not others.**

   The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others. Order No. 672 at P 322.

   The proposed interpretation does not change the applicability of the FERC-approved RRS. BAL-002-WECC-2a complies with Order 672 in that it applies only to Balancing Authorities and Reserve Sharing Groups in the Western Interconnection.

4. **Proposed reliability standards must be clear and unambiguous as to what is required and who is required to comply.**

   The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability. Order No. 672 at P 325.

   The proposed interpretation does not change the requirements of the standard or the applicability. It was posted for separate 45-day comment periods at WECC and NERC. There were no negative concerns, no minority positions, and no requests for changes in either posting. When balloted, the Ballot Pool approved the project with a 100 percent weighted sector approval, with zero negative votes and three abstentions.

5. **Proposed reliability standards must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.**

   The proposed interpretation does not change or impact any of the FERC-approved VRFs or VSLs.

6. **Proposed reliability standards must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.**

   There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner. Order No. 672 at P 327.

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[2] "Fn 44 Petition, Exhibit C at 20."

The proposed interpretation does not change any of the Measures in the FERC-approved RRS.

7. **Proposed reliability standards should achieve a reliability goal effectively and efficiently - but does not necessarily have to reflect "best practices" without regard to implementation cost.**

   The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently. Order No. 672 at P 328.

   The proposed interpretation does not change any of the reliability-related substance of the underlying FERC-approved RRS.

8. **Proposed reliability standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect bulk power system reliability.**

   The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability. Order No. 672 at P 329.

   The proposed interpretation does not change any of the reliability-related substance of the underlying FERC-approved RRS.

9. **Proposed reliability standards may consider costs to implement for smaller entities but not at consequence of less than excellence in operating system reliability.**

   A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it. Order No. 672 at P 330.

   The proposed interpretation does not change any of the reliability-related substance of the underlying FERC-approved RRS.

10. **Proposed reliability standards must be designed to apply throughout North America to the maximum extent achievable with a single reliability standard while not favoring one area or approach.**

A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard. Order No. 672 at P 331.

The proposed interpretation does not alter or otherwise change the applicable entities operating within the Western Interconnection that are identified in the FERC-approved RRS.

11. Proposed reliability standards should cause no undue negative effect on competition or restriction of the grid.

As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another. Order No. 672 at P 332

The proposed interpretation is not anticipated to have any negative impact on competition. Rather, due to the clarification provided additional markets may be availed to fulfil the associated reserve requirements.

12. The implementation time for the proposed reliability standards must be reasonable.

In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability. Order No. 672 at P 333

The requested implementation time of immediately upon regulatory approval is reasonable. In light of the earlier July 18, 2013 FERC Order 789, entities may already be implementing the practices clarified in the interpretation.

13. The reliability standard development process must be open and fair.

Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed

Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission. Order No. 672 at P 334

WECC followed the standard development process approved by FERC in effect at the time of each step in the process.

In accordance with the Procedures, effective March 1, 2012, all drafting team meetings are open to the public.

Two drafting team meetings were held. One meeting addressed the issue; one meeting addressed responses to comments.

Notice of the meetings was provided to NERC, posted on the WECC Web site and embedded in the minutes of each meeting. Meeting minutes are posted on the WECC Web site and accessible by the public.

All meetings were supported by a telephone conference bridge associated with an on-line internet visual capability allowing all participants to see the document(s) as they were being developed. Further, this team held an open-mic standards briefing prior to balloting affording the industry an additional opportunity to have its questions addressed.

The proposed interpretation was posted for separate 45-day comment periods at WECC and at NERC. Neither posting resulted in any requests for change.

Comments and their responses are included in this filing and posted on the WECC Web Site at the WECC-0114 Project Page on the Submitted and Review Comments accordion.

14. Proposed reliability standards must balance with other vital public interests.

Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard. Order No. 672 at P 335

WECC is not aware of any other vital public interests. No such balancing concerns were raised or noted.

15. Proposed reliability standards must consider any other relevant factors.

In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed. Order No. 672 at P 323

WECC is not aware of any other relevant factors and none were raised during development.

Attachment J: Drafting Team Roster

WECC-0114 BAL-002-WECC-2a
Contingency Reserve
Request for Interpretation

Below please find a biographical snapshot for the members of the WECC-0114 BAL-002-WECC-2a, Contingency Reserve – Interpretation Drafting Team.

Bart McManus

Mr. McManus received his Bachelor of Science in Electrical Engineering from the University of Washington and has been at the Bonneville Power Authority (BPA) since 1994. Mr. McManus was the lead programmer for the Automatic Generation Control (AGC) system for multiple years, before becoming the lead for AGC and other Balancing Authority Area Operations at BPA. Mr. McManus began working on wind integration issues in 2006, and now serves as the wind integration lead for BPA Transmission Operations.

Clyde Loutan

Clyde Loutan is presently a Senior Advisor at the California Independent System Operator Corporation (ISO) focusing on power system operation performance, and was the Principal Investigator for several technical studies including the ISO's renewable resource integration reports published in 2007 and 2010. Mr. Loutan serves on the North American Electric Reliability Corporation (NERC) Frequency Responsive Reserve and the NERC Reliability Based Control Standards workgroups.

Mr. Loutan previously worked at the Pacific Gas and Electric Company for 14 years in various capacities such as Real Time System Operations, Transmission Planning and High Voltage Protection.

Mr. Loutan is a licensed professional engineer in the State of California. He holds a Bachelor of Science and a Master of Science degree in Electrical Engineering from Howard University in Washington D.C., and is a senior member of the Institute of Electrical and Electronic Engineers.

David Frederick

Mr. Frederick served as the Interpretation Drafting Team chair for WECC-0114, drafting team chair for WECC-0103, and Member of the WEC-0083 drafting team that drafted the original underlying standard being interpreted in this filing.

Mr. Frederick is a Cost/Plant/Power Production Analyst for Salt River Project (SRP). He has worked in merchant and reliability areas at SRP since 1999. He was Administrator of the Southwest Reserve Sharing Group until 2014.

Mr. Frederick is a NERC-Certified System Operator in Balancing, Interchange, and

Transmission Operations and holds a Bachelor of Science degree in Accountancy.

David Lemmons

Mr. Lemmons began his career in the electric industry with Southwestern Public Service Company (SPS) in Amarillo, Texas, in 1989. He spent eight years in the rates and regulation department where he performed rate of return analyses, designed rates and worked with other regulatory issues.

In 1997, Mr. Lemmons transferred to the energy trading department during the merger between SPS and Public Service Company of Colorado (PSCo). In this capacity, with Xcel Energy and its predecessor, New Century Energies, he analyzed the electric system loads and resources for day-ahead and real-time operations and trading — working with generation and fuel procurement to ensure resources were ready and available to serve loads.

In 2001, Mr. Lemmons took the position of Senior Manager, Market Operations, representing Xcel Energy at electric reliability, RTO development and system operation meetings throughout the United States, as well as providing support for state and Federal regulatory proceedings. Mr. Lemmons has chaired the WECC-0083 BAL-002-WECC-1 Standard Drafting Team, the NERC Project 2007-12 Standard Drafting team and is a team member on the NERC Project 2010-14.1 Standard Drafting Team.

In 2013, Mr. Lemmons took his current position, Senior Consultant, Standards Policy and Compliance. In this position, Mr. Lemmons is responsible for working with power plants to ensure compliance with Reliability Standards, train plant operators as needed and to represent Xcel Energy generation in the development of new standards.

He holds a Master of Science degree in finance and economics from West Texas A&M University.

John Tolo

Mr. Tolo is currently employed by Tucson Electric Power as Sr. Director, System Control and Reliability and Planning, and has been in the utility business for 29 years. Mr. Tolo has held positions in power production and distribution, transmission, and generation operations. He has memberships in the NERC Resources Subcommittee, the WECC Performance Work Group, served as chair of the WECC Operating Committee, chair of the WECC Joint Guidance Committee, and is a member of the BAL-004-WECC-01 and WECC-0068 drafting teams.

Phil Tice

Mr. Tice, manager wholesale contracts and regulations at Deseret Power Electric Cooperative, Inc., has more than 40 years of electric utility experience (20 years with Deseret). Mr. Tice held engineering and supervisory positions with utilities for 24 years in plant design, operation and maintenance. Mr. Tice has been engaged in wholesale

electricity marketing and associated Federal regulations for the past 16 years. Mr. Tice is a past chair of the WECC Market Interface Committee, as well as Deseret's voting representative on the WECC Operating Committee.

Mr. Tice holds a Bachelor of Science in mechanical engineering from Indiana Institute of Technology in 1970. Mr. Tice is a registered professional engineer licensed by the State of Pennsylvania.

Attachment K: Ballot Pool Members

WECC-0114 BAL-002-WECC-2a Contingency Reserve Request for Interpretation

Ballot Body Roster **BAL-002-WECC-2a**

Ballot Period: **7/23/2015- 8/7/2015**

Title	Company	Sector	Vote	Comments	Created By
WECC-0114	Arizona Public Service Company	Marketers and Brokers	Yes		Todd Komaromy
WECC-0114	Arizona Public Service Company	Generation	Yes		Michelle Amarantos
WECC-0114	Arizona Public Service Company	Distribution	Yes		Michelle Amarantos
WECC-0114	Arizona Public Service Company	System Coordination	Yes		Stephanie Little
WECC-0114	Arizona Public Service Company	Transmission	Yes		Gary Nolan
WECC-0114	Avista Corporation	Marketers and Brokers	Yes		Scott Kinney
WECC-0114	Avista Corporation	Transmission	Yes		Bryan Cox
WECC-0114	Balancing Authority of Northern California	System Coordination	Yes		Joe Tarantino
WECC-0114	Bonneville Power Administration	Transmission	Yes		Donald Watkins
WECC-0114	Bonneville Power Administration	Marketers and Brokers	Yes		Alex Spain
WECC-0114	Bonneville Power Administration	System Coordination	Yes	We are in agreement with this interpretation.	Francis Halpin
WECC-0114	Bonneville Power Administration	Distribution	Yes		Rebecca Berdahl
WECC-0114	BC Hydro and Power Authority	Transmission	Abstain		Patricia Robertson

WECC-0114	BC Hydro and Power Authority	System Coordination	Abstain		Patricia Robertson
WECC-0114	BC Hydro and Power Authority	Distribution	Yes		Pat Harrington
WECC-0114	City of Tacoma, Department of Public Utilities, Light Division	System Coordination	Yes		Twila Hofer
WECC-0114	City of Tacoma, Department of Public Utilities, Light Division	Generation	Yes		Karen Hedlund
WECC-0114	City of Tacoma, Department of Public Utilities, Light Division	Transmission	Yes		Joseph Wilson
WECC-0114	City of Tacoma, Department of Public Utilities, Light Division	Distribution	Yes		Chad Edinger
WECC-0114	Iberdrola Renewables	Generation	Yes		Joe Polen
WECC-0114	NaturEner Power Watch, LLC	Generation			Marc DeNarie
WECC-0114	Platte River Power Authority	Marketers and Brokers	Yes		Carol Ballantine
WECC-0114	Platte River Power Authority	Generation	Abstain	N/A	Tyson Archie
WECC-0114	Platte River Power Authority	Transmission			Terry Baker
WECC-0114	Portland General Electric Company	Transmission			John Walker
WECC-0114	Powerex Corp.	Marketers and Brokers			Raj Hundal
WECC-0114	Public Service Company of Colorado	Marketers and Brokers	Yes		Peter Colussy
WECC-0114	Public Service Company of Colorado	Distribution	Yes		Chad Nickell
WECC-0114	Public Service Company of Colorado	System Coordination	Yes		Robert Staton
WECC-0114	Public Service Company of Colorado	Transmission	Yes		Robert Staton
WECC-0114	Public Service Company of New Mexico	System Coordination	Yes		Laurie Williams

WECC-0114	Public Service Company of New Mexico	Generation	Yes	Laurie Williams
WECC-0114	Public Service Company of New Mexico	Distribution	Yes	Laurie Williams
WECC-0114	Public Service Company of New Mexico	Transmission	Yes	Laurie Williams
WECC-0114	Public Service Company of New Mexico	Marketers and Brokers	Yes	Laurie Williams
WECC-0114	Puget Sound Energy, Inc.	Transmission	Yes	Theresa Rakowsky
WECC-0114	Puget Sound Energy, Inc.	Generation		Lynda Kupfer
WECC-0114	Puget Sound Energy, Inc.	Marketers and Brokers		Andrea Basinski
WECC-0114	Sacramento Municipal Utility District	System Coordination	Yes	Joe Tarantino
WECC-0114	Sacramento Municipal Utility District	Transmission	Yes	Joe Tarantino
WECC-0114	Sacramento Municipal Utility District	Generation	Yes	Joe Tarantino
WECC-0114	Sacramento Municipal Utility District	Distribution	Yes	Joe Tarantino
WECC-0114	Sacramento Municipal Utility District	Marketers and Brokers	Yes	Joe Tarantino
WECC-0114	Salt River Project Agricultural Improvement and Power District	Transmission		Kevin Nielsen
WECC-0114	Salt River Project Agricultural Improvement and Power District	Distribution		Kevin Nielsen

WECC-0114	Salt River Project Agricultural Improvement and Power District	Generation			Kevin Nielsen
WECC-0114	Salt River Project Agricultural Improvement and Power District	System Coordination			Kevin Nielsen
WECC-0114	Salt River Project Agricultural Improvement and Power District	Marketers and Brokers			William Abraham
WECC-0114	Seattle City Light	Generation	Yes		Mike Haynes
WECC-0114	Seattle City Light	Transmission	Yes		Hao Li
WECC-0114	Seattle City Light	Marketers and Brokers			Dennis Sismaet
WECC-0114	Southern California Edison - Transmission & Distribution	Distribution	Yes		Steven Mavis
WECC-0114	Southern California Edison - Transmission & Distribution	Transmission	Yes		Steven Mavis
WECC-0114	Tri-State Generation and Transmission Association, Inc. - Reliability	Transmission	Yes		Tracy Sliman
WECC-0114	Tucson Electric Power	System Coordination			John Tolo
WECC-0114	Tucson Electric Power	Transmission			John Tolo
WECC-0114	Tucson Electric Power	Distribution			John Tolo
WECC-0114	Tucson Electric Power	Generation			John Tolo
WECC-0114	Western Area Power Administration – LAP	Marketers and Brokers	Yes		Kenneth Otto
WECC-0114	Western Area Power Administration - Rocky Mountain Region	Transmission	Yes	Interpretation follows the line of reasoning followed by FERC Order 789, Paragraph 48 using the terminology of the NERC drafting team for BAL-002	James Hirning

Attachment L: Final Ballot Results

WECC-0114 BAL-002-WECC-2a
Contingency Reserve
Request for Interpretation

WECC Standards Voting Summary

Ballot Name: **WECC-0114**
BAL-002-WECC-2a
Contingency Reserve - Request for Interpretation

Ballot Pool Opened: 7/6/2015 - 7/21/2015
Ballot Period: 7/23/2015 - 8/7/2015
Total Ballot Pool: 60
Total Votes: 44

Quorum: 73.3%
Weighted Vote: 100.0%
Ballot Results The Document has Passed

	Total In Ballot Pool	Votes Non-Abstain	Sector Weight	Yes Votes	Weighted Segment Vote	No Votes	Abstain	Total Votes* for Quorum	Didn't Vote
Distribution	10	8	0.8	8	80.0%	0	0	8	2
End User Representative	0	0	0	0	0.0%	0	0	0	0
Generation	11	6	0.6	6	60.0%	0	1	7	4
Marketers and Brokers	12	8	0.8	8	80.0%	0	0	8	4
Other Non-Registered WECC Members and Participating Stakeholders	0	0	0	0	0.0%	0	0	0	0
State and Provincial Representatives	0	0	0	0	0.0%	0	0	0	0
System Coordination	10	7	0.7	7	70.0%	0	1	8	2
Transmission	17	12	1	12	100.0%	0	1	13	4
Totals	60	41	3.9	41	**100.0%**	0	3	44	16

WECC
WESTERN ELECTRICITY COORDINATING COUNCIL
155 North 400 West, Suite
200 Salt Lake City, Utah
84103-1114

Attachment O: WECC Standards Committee Roster

WECC-0114 BAL-002-WECC-2a Contingency Reserve Request for Interpretation

The following individuals are those assigned to the WECC Standards Committee as of September 15, 2015.

Sector	Name	Organization
1 Transmission	Dana Cabbell	Southern California Edison
2 Generation	Angela Small	NAES
3 Marketers and Brokers	Tanner Brier	Bonneville Power Administration
4 Distribution	Warren Rust	Colorado Springs Utilities
5 System Coordination	Joseph Tarantino	Sacramento Muni. Utility District
6 End User Representative	Caitlin Liotiris	Energy Strategies
7 State and Provincial	David Walker	Wyoming Public Service Commission
8 Other Non-Registered Entities	Crystal Musselman	Proven Compliance Solutions
Board of Directors	Joe McArthur	Non-Affiliate Director / WSC Chair

Attachment R1: Response to Comments
WECC-0114 BAL-002-WECC-2a
Contingency Reserve
Request for Interpretation

Posting #1

The WECC-0114, BAL-002-WECC-2a, Request for Interpretation Drafting Team (DT) thanks everyone who submitted comments on the proposed documents.

Posting

This document was last posted for a 45-day public comment period from May 4 through June 18, 2015.

WECC distributed the notice for the posting on May 1, 2015. The DT asked stakeholders to provide feedback on the proposed document through a standardized electronic template. WECC received comments from one company representing three of the eight Industry Segments, as shown in the table on the following page.

Location of Comments

All comments received on the document can be viewed in their original format on the project page under the "Submit and Review Comments" accordion.

Changes in Response to Comment

After consideration of comments received, the DT made no further changes to the project.

Action Plan

On June 19, 2015, the DT agreed by consensus to forward the project to the WECC Standards Committee with a request for ballot.

Contacts and Appeals

If you feel your comment has been omitted or overlooked, please contact the Manager, WECC Standards Processes, W. Shannon Black, at sblack@wecc.biz. In addition, there is a WECC Reliability Standards Appeals Process.

The WECC Standards Voting Sectors are:

1 — Transmission Sector

2 — Generation Sector

3 — Marketers and Brokers Sector

4 — Distribution Sector

5 — System Coordination Sector

6 — End Use Representative Sector

7 — State and Provincial Representatives Sector

8 — Other Non-Registered WECC Members and Participating Stakeholders Sector

Commenter		Organization	WECC Standards Voting Sectors							
			1	2	3	4	5	6	7	8
1	Molly Devine	Idaho Power	X	X		X				

Index to Questions, Comments, and Responses

Question

1. The drafting team invites comments on all aspects of the proposed document.

Summary Consideration:	See summary in the preamble of this document.		
Commenter	Yes	No	Comment
Idaho Power			Idaho Power agrees with the interpretation provided in this posting.
The DT appreciates Idaho Power's continued involvement in the standards development process.			

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Attachment R2
Consideration of Comments
Regional Reliability Interpretation BAL-002-WECC-2a

The Regional Reliability Standard Interpretation Drafting Team (IDT) thanks all those who submitted comments on the BAL-002-WECC-2a, Contingency Reserve, Request for Interpretation. No adverse comments, minority opinions, or requests for change were provided during the posting. As a result, no further changes were made to the project.

This standard was posted for a 45-day public comment period from August 4, 2015 through September 17, 2015. Stakeholders were asked:

1. Do you agree the proposed interpretation was developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?

2. Does the proposed interpretation pose an adverse impact to reliability or commerce in a neighboring region or interconnection?

3. Does the proposed interpretation pose a serious and substantial threat to public health, safety, welfare, or national security?

4. Does the proposed interpretation pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?

Three entities provided comments. All three agreed that the proposed interpretation: 1) was developed in a fair and open process, 2) does not pose an adverse impact to reliability or commerce, 3) does not pose a serious and substantial threat to public health, safety, welfare or national security, and 4) does not pose a serious and substantial burden on competitive markets within the interconnection.

NERC documents and information about this project are available on the NERC Regional Reliability Standards Under Development page.

Exhibit E

Interpretation Drafting Team Roster

Drafting Team Roster WECC-0114 BAL-002-WECC-2a Contingency Reserve Request for Interpretation

Below please find a biographical snapshot for the members of the WECC-0114 BAL-002-WECC-2a, Contingency Reserve – Interpretation Drafting Team.

Bart McManus

Mr. McManus received his Bachelor of Science in Electrical Engineering from the University of Washington and has been at the Bonneville Power Authority (BPA) since 1994. Mr. McManus was the lead programmer for the Automatic Generation Control (AGC) system for multiple years, before becoming the lead for AGC and other Balancing Authority Area Operations at BPA. Mr. McManus began working on wind integration issues in 2006, and now serves as the wind integration lead for BPA Transmission Operations.

Clyde Loutan

Clyde Loutan is presently a Senior Advisor at the California Independent System Operator Corporation (ISO) focusing on power system operation performance, and was the Principal Investigator for several technical studies including the ISO's renewable resource integration reports published in 2007 and 2010. Mr. Loutan serves on the North American Electric Reliability Corporation (NERC) Frequency Responsive Reserve and the NERC Reliability Based Control Standards workgroups.

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Mr. Loutan is a licensed professional engineer in the State of California. He holds a Bachelor of Science and a Master of Science degree in Electrical Engineering from Howard University in Washington D.C., and is a senior member of the Institute of Electrical and Electronic Engineers.

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Mr. Frederick served as the Interpretation Drafting Team chair for WECC-0114, drafting team chair for WECC-0103, and Member of the WEC-0083 drafting team that drafted the original underlying standard being interpreted in this filing.

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electricity marketing and associated Federal regulations for the past 16 years. Mr. Tice is a past chair of the WECC Market Interface Committee, as well as Deseret's voting representative on the WECC Operating Committee.

Mr. Tice holds a Bachelor of Science in mechanical engineering from Indiana Institute of Technology in 1970. Mr. Tice is a registered professional engineer licensed by the State of Pennsylvania.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RM16-10-000**

SUPPLEMENTAL INFORMATION FOR PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND WESTERN ELECTRICITY COORDINATING COUNCIL FOR APPROVAL OF RETIREMENT OF REGIONAL RELIABILITY STANDARD TOP-007-WECC-1a

The North American Electric Reliability Corporation ("NERC") and the Western Electricity Coordinating Council ("WECC") hereby submit supplemental information ("Supplement") to their March 23, 2016 petition ("Petition") filed in the above-captioned docket requesting approval of the retirement of WECC regional Reliability Standard TOP-007-WECC-1a – System Operating Limits.[1] This Supplement provides additional background information on TOP-007-WECC-1a, the purpose of the proposed retirement, and the manner in which the reliability of the 40 Transmission paths currently subject to TOP-007-WECC-1a is addressed under the continent-wide Transmission Operations ("TOP") and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards.[2]

As discussed below, regional Reliability Standard TOP-007-WECC-1a reflects a historical, path-centric operating paradigm unique to the Western Interconnection. This paradigm is focused on identifying a single, pre-determined transfer capability value for an entire Transmission path,

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

[2] As provided in Section 4 of the standard, regional Reliability Standard TOP-007-WECC-1a applies only to the 40 Transmission paths listed in the table titled "Major WECC Transfer Paths in the Bulk Electric System," provided at https://www.wecc.biz/Reliability/TableMajorPaths4-28-08.pdf.

which, if operated within, was intended to provide for reliable operation by preventing a pre-determined limiting Contingency from resulting in an exceedance of a specific thermal Facility Rating, system voltage limit, or stability limit. With the development of advanced applications for Real-time analysis, however, the paradigm upon which TOP-007-WECC-1a is based no longer aligns with current operating practices nor does it provide an optimal framework for reliably operating the Bulk-Power System ("BPS").

The purpose of the proposed retirement of TOP-007-WECC-1a is to shift away from the path-centric paradigm and allow entities in the Western Interconnection to align their operating practices with the framework established in the continent-wide TOP/IRO Reliability Standards approved in Order No. 817.[3] As the Federal Energy Regulatory Commission ("FERC" or "Commission") recognized, that framework provides for a comprehensive and reliable approach to, among other things, achieving the objective of operating within acceptable pre- and post-Contingency reliability criteria (i.e., within System Operating Limits ("SOLs") and Interconnection Reliability Operating Limits ("IROL").[4] The retirement of TOP-007-WECC-1a would have no adverse effect on reliability. As discussed below, there is no reliability need to continue the historical, path-centric approach reflected in TOP-007-WECC-1a or to treat the facilities comprising the 40 Transmission paths subject to TOP-007-WECC-1a any differently than all other facilities are treated under the continent-wide TOP/IRO Reliability Standards. Each of the facilities comprising these 40 Transmission paths would be monitored in accordance with the Commission-approved TOP/IRO Reliability Standards and subject to associated mitigation

[3] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178, 80 Fed. Reg. 73977 (2015).

[4] *Id*. at PP 14-17.

requirements should there be an expected or actual exceedance of an SOL or IROL on those facilities.

Following additional discussion of the history of TOP-007-WECC-1a (Section I.a), the operational paradigm underlying the regional standard (Section I.b), and the purpose of retiring the regional standard (Section II), this Supplement discusses the following:

- The manner in which Peak Reliability ("Peak"), as the Reliability Coordinator for the Western Interconnection (except in Alberta, Canada), and Transmission Operators and Balancing Authorities would continue to monitor and assess conditions on the 40 Transmission paths under the continent-wide TOP/IRO Reliability Standards. (Section III.a).

- Whether the 30-minute mitigation requirement in TOP-007-WECC-1a would continue to apply to the 40 Transmission paths following retirement of the standard and, if not, the basis for no longer applying such a requirement to each path. (Section III.b).

- The process for establishing SOLs and IROLs for each of the facilities comprising the 40 Transmission paths and the type of limitations associated with those paths. (Section III.c).

- Peak's intent to modify its methodology for establishing SOLs and IROLs and the manner in which such revisions could impact the evaluation of the 40 Transmission paths under the TOP/IRO Reliability Standards. (Section III.d).

- Peak's use of a 1000 MW threshold in its current methodology for determining IROLs and the manner in which that threshold applies to the 40 Transmission paths subject to TOP-007-WECC-1a. (Section III.e).

I. Background

a. History of Regional Reliability Standard TOP-007-WECC-1a

Regional Reliability Standard TOP-007-WECC-1a and the operating paradigm upon which it is based derive from the reliability criteria in WECC's Reliability Management System ("RMS"), which predates the enactment of the Energy Policy Act of 2005 ("EPAct 2005")[5] and NERC's mandatory Reliability Standards under Section 215 of the Federal Power Act ("FPA").[6]

[5] Energy Policy Act of 2005, Pub. L. No. 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005).

[6] 16 U.S.C. § 824o (2012).

The RMS, which is no longer in effect, was developed in the late 1990s in response to a series of black-outs in the Western Interconnection and established the reliability criteria to which Transmission Operators in the Western Interconnection agreed to be bound.[7] Among other things, the RMS reliability criteria set forth an operating paradigm focused on identifying a single, pre-determined maximum flow value for major WECC Transmission paths and requiring Transmission Operators to operate within that value to achieve reliable operations.

More specifically, the RMS criteria provided that actual power flows for certain major Transmission paths in the Western Interconnection shall at no time exceed the Operating Transfer Capability Limits ("OTC") for those paths for more than 20 minutes for stability limited paths or for more than 30 minutes for thermally limited paths.[8] As provided in the RMS, OTC is determined on a seasonal basis and represents "the maximum amount of actual power that can be transferred over direct or parallel transmission elements comprising: (1) an interconnection from one Control Area to another Control Area;[9] or (2) a transfer path within a Control Area.[10] The OTC thus reflected a pre-determined transfer capability value for an entire path (a "Path OTC") which, if operated within, was intended to prevent a pre-determined limiting Contingency from

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[7] The RMS was initially established by Western Systems Coordinating Council ("WSCC"), which is one of the three predecessor entities to WECC. WECC was formed on April 18, 2002, by the merger of the WSCC, Southwest Regional Transmission Association, and Western Regional Transmission Association. The Commission approved the initial RMS criteria in 1999. *Western Systems Coordinating Council*, 87 FERC ¶ 61,060 (1999).

[8] Under the RMS, OTC is defined as "the maximum value of the most critical system operating parameter(s) which meets: (a) precontingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) transient criteria as determined by equipment loading capability and acceptable voltage conditions, (c) transient performance criteria, and (d) post contingency loading and voltage criteria."

[9] The RMS defined "Control Area" as "an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the Western Interconnection. As used herein, the term 'Control Area' shall have the same meaning as the term 'Balancing Authority Area' or 'Balancing Authority,' as applicable, as such terms are used in the NERC Standards."

[10] In this respect, OTC is closely associated with the *NERC Glossary* term "Total Transfer Capability," which is defined as "[t]he amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions."

resulting in an exceedance of a specified thermal Facility Rating, system voltage limit, or stability limit.[11] The OTC criteria essentially married the concept of operating limits and transfer limits in a single parameter for WECC Transmission paths.

Following the enactment of EPAct 2005 and the establishment of mandatory Reliability Standards applicable to all owners, operators, and users of the BPS, WECC sought to translate certain of its existing practices under its RMS reliability criteria into regional Reliability Standards to supplement the continent-wide Reliability Standards the Commission approved in Order No. 693.[12] To that end, WECC established a task force to identify criteria in the RMS that should be binding on all BPS users, owners, and operators in the Western Interconnection, not just the Transmission Operators subject to the RMS. The task force chose eight of the identified criteria, which had the highest priority and could be implemented in the near term for translation into regional Reliability Standards.

The task force recommended the continued application of the Path OTC paradigm on the assumption that it would continue to provide an effective way to ensure that the system was operated within acceptable limits, consistent with the analysis tools available at that time. The primary processes and analysis tools that operators in the Western Interconnection used to achieve pre- and post-Contingency reliability at that time included: (1) offline studies performed by engineers; and (2) SCADA systems monitored by System Operators. At that time, state estimation, Real-time Contingency analysis, and other control room analysis tools more widely used today to

[11] For example, a thermally limited OTC was a pre-determined WECC path transfer capability value that was intended to prevent an identified Contingency from causing exceedance of an identified Facility's thermal facility rating. A transient stability limited OTC was a pre-determined WECC path transfer capability value that was intended to prevent an identified Contingency from resulting in violation of WECC-established transient voltage dip criteria or transient frequency dip criteria.

[12] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 FR 16416 (2007), FERC Stats. & Regs. ¶ 31,242, order on reh'g, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

assess conditions in the day-ahead time horizon and in Real-time were in their infancy and not generally used in operations in the Western Interconnection. Further, there was no continent-wide requirement to conduct Operational Planning Analyses ("OPAs") or Real-time Assessments ("RTAs").

On March 26, 2007, NERC filed for Commission approval eight WECC regional Reliability Standards, including WECC-TOP-STD-007-0, based on the task force's recommendation.[13] Regional Reliability Standard WECC-TOP-STD-007-0 was a direct translation of the OTC reliability criteria from the RMS and identified 40 Transmission paths subject to the requirements therein. In filing for approval, NERC and WECC noted that WECC-TOP-STD-007-0 was more stringent than the corresponding continent-wide Reliability Standard TOP-007-0 in that the regional standard provided that any exceedances of OTC, regardless of whether there was also an applicable IROL designation, be addressed within 30 minutes (and 20 minutes for stability limited paths).

On June 8, 2007, the Commission approved the eight WECC regional Reliability Standards as mandatory and enforceable in the Western Interconnection.[14] The Commission found that WECC-TOP-STD-007-0 met the criteria for regional Reliability Standards as it was more stringent than the corresponding continent-wide Reliability Standard TOP-007-0.[15] The Commission also directed modifications to WECC-TOP-STD-007-0 to address certain shortcomings with respect to formatting, aligning WECC regional definitions with the *NERC Glossary*, and removing compliance and measure references.[16]

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[13] *North American Electric Reliability Corporation, Request for Approval of Regional Reliability Standards of the Western Electricity Coordinating Council*, Docket No. RR07-11-000 (Mar. 26, 2007).

[14] *North American Electric Reliability Corporation*, 119 FERC ¶ 61,260 (2007).

[15] *Id*. at P 104.

[16] *Id*. at P 110.

In response to the Commission's directive and to make certain other changes, on March 25, 2009, NERC submitted a petition for approval of regional Reliability Standard TOP-007-WECC-1, which was designed to replace and improve upon WECC-TOP-STD-007-0.[17] In Order No. 752, issued on April 21, 2011, the Commission approved TOP-007-WECC-1 and the retirement of WECC-TOP-STD-007-0.[18] Regional Reliability Standard TOP-007-WECC-1 carries forward the operating paradigm from the RMS and WECC-TOP-STD-007-0 focused on identifying a single, pre-determined maximum transfer capability flow value for an entire Transmission path and requiring Transmission Operators to operate within that value to achieve reliable operations.[19]

Among other changes, TOP-007-WECC-1a uses the continent-wide *NERC Glossary* term "SOL" rather than the WECC regional term "OTC." Although, as the Commission recognized, those terms do not have a one-to-one relationship,[20] the change in terminology was not intended to and did not substantively modify the obligation under the regional standard or existing practices in the Western Interconnection for establishing the single, pre-determined transfer value within which the 40 applicable Transmission paths must be operated.[21] As stated in Order No. 752, the Commission initially questioned the appropriateness of the change in terminology:

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[17] *Petition of the North American Electric Reliability Corporation for Approval of Proposed Western Electricity Coordinating Council Regional Reliability Standard TOP-007-WECC-1 – System Operating Limits*, Docket No. RM09-14-000 (Mar. 25, 2009).

[18] *North American Electric Reliability Corporation*, Order No. 752, 135 FERC ¶ 61,062, 76 Fed. Reg. 23470 (2011). On June 18, 2014, the Commission issued approved an interpretation to TOP-007-WECC-1, such that the numbering of the standard became TOP-007-WECC-1a. *N. Elec. Reliability Corp.*, Docket No. RD14-18-000 (June 18, 2014) (unpublished letter order).

[19] Specifically, Requirement R1 of TOP-007-WECC-1 provides: "When the actual power flow exceeds an SOL for a Transmission path, the Transmission Operators shall take immediate action to reduce the actual power flow across the path such that at no time shall the power flow for the Transmission path exceed the SOL for more than 30 minutes."

[20] As noted above, OTC marries the concepts of transfer capability and operating limits, and, in that respect, more closely align with the *NERC Glossary* term "Total Transfer Capability" than the term "SOL."

[21] Order No. 752 at PP 32-35.

> In the NOPR, the Commission questioned the appropriateness of replacing the term "operating transfer capability" limit as used in the currently-effective Reliability Standard TOP-STD-007-0, with the term "SOL," as used in TOP-007-WECC-1. The Commission stated that the term "SOL" is used within the Western Interconnection to refer to the facility or element that presents the most limiting of the prescribed operating criteria for the rated system path. Whereas, the OTC limit corresponds to the "maximum amount of actual power transferred over direct or parallel transmission elements from one transmission operator to another transmission operator." The Commission expressed concern that the terms SOL and OTC appear to measure different things.[22]

Nevertheless, the Commission approved the change in response to WECC's comments that the replacement of "OTC" with "SOL" was to address the Commission's concerns regarding the proliferation of regional terms and would not substantively change existing practices nor the manner in which the requirement would be enforced.[23] WECC stated that the methodologies for establishing SOLs and OTCs in the Western Interconnection are the same and result in the same value.[24] As a result, OTCs became SOLs in the Western Interconnection.

In addition to the change in terms, TOP-007-WECC-1 extended the mitigation time for returning flows on stability limited paths to within the "Path SOL" from 20 minutes to 30 minutes. The Commission approved the extension on the grounds that having a uniform time for both stability-limited and thermally-limited paths would reduce confusion among operators.[25]

b. Legacy Operational Paradigm Reflected in TOP-007-WECC-1a

The Path OTC/SOL concept developed under the RMS and carried forward into WECC regional Reliability Standards TOP-STD-007-0 and, ultimately, TOP-007-WECC-1a, presumes an operational paradigm characterized by the following:

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22 Order No. 752 at P 32 (internal citations omitted).

23 Order No. 752 at P 35.

24 The SOL methodology for the Western Interconnection developed pursuant to the Facilities Design, Connections, and Maintenance ("FAC") group of Reliability Standards was consistent with the manner in which it calculated OTC under the RMS and WECC-TOP-STD-007-0.

25 *Id*. at P 31.

- A study, assessment, or analysis needs to be performed ahead of time to establish a Path OTC/SOL that achieves acceptable Bulk Electric System ("BES") system performance.
- The established Path OTC/SOL (a maximum flow value on an interface or cut plane) is then communicated and coordinated with operators and other impacted entities prior to implementation.
- Transmission Operators are then given Operating Plans for operating below the Path OTC/SOL with the presumption that doing so will result in reliable operations.

More specifically, under this paradigm, Transmission Operators in the Western Interconnection, through their participation in sub-regional study groups, perform seasonal studies for each of the applicable Transmission paths to determine a Path SOL for use during the upcoming season. A primary objective of these seasonal studies is to confirm that the WECC Path Rating for each applicable path is achievable, given the expected system conditions for that season.[26] If the seasonal study demonstrates that the WECC Path Rating is achievable for that season, the WECC Path Rating becomes the Path SOL for the season. If the seasonal study shows that WECC Path Rating (plus some margin) is reached without encountering pre- or post-Contingency reliability issues, the Path is considered to be "flow limited" for that season and the "flow limited" WECC Path Rating serves as the seasonal Path SOL. If the seasonal study does not demonstrate that the WECC Path Rating is achievable for that season, the Transmission Operator determines, in accordance with the Reliability Coordinator's SOL methodology under Reliability Standard FAC-011, a lesser Path flow value that provides for acceptable thermal, voltage, and stability criteria performance for the pre- and post-Contingency state. This value becomes the Path SOL for the season. The establishment of the Path OTC/SOL included Transfer Capability, scheduling limits, allocations, and commercial considerations.

[26] Each year WECC publishes the WECC Path Rating Catalog, which identifies ratings for all of the defined paths in WECC, not just the 40 paths subject to TOP-007-WECC-1a. The ratings are most closely related to a Total Transfer Capability, as defined in the *NERC Glossary*.

As noted, once the seasonal Path SOL is established, it is communicated to Transmission Operators, along with an operating plan for operating below the Path SOL. The operating plan sets forth the steps operators must take to meet the 30-minute requirement in the event of an exceedance of the Path SOL. Throughout the season, the Transmission Operator may reduce the Path SOL as necessary based on their studies of anticipated outage conditions. Under TOP-007-WECC-1a, when the actual power flow on an applicable Transmission path exceeds its Path OTC/SOL in Real-time operations, operators must initiate actions, up to and including pre-Contingency load shedding, in accordance with the operating plan, to reduce that Path's flow below the Path SOL within 30 minutes.

To illustrate, WECC Path 30 (TOT 1A) – which is comprised of the following three transmission lines: (1) the Bears Ears-Bonanza 345 kV line, the Hayden-Artesia 138 kV line, and the Meeker-Rangely 138 kV line – currently has a Path SOL of 650 MW for flows going east to west. The 650 MW Path SOL is based on transfer studies indicating that if there is a Contingency outage of the Bears Ears-Bonanza 345 kV line when east to west flows on Path 30 (TOT 1A) exceed 650 MW, there is a significant risk that the Hayden-Artesia 138 kV line would exceed its emergency Facility Rating. As a result, a Path SOL of 650 MW was established to help ensure that a Contingency of the Bears Ears – Bonanza 345 kV line does not cause the Hayden – Artesia 138 kV line to exceed its emergency Facility Rating at that transfer level. Under TOP-007-WECC-1a, should flows on the Path exceed 650 MW, Transmission Operators must take action, up to and including load shedding, to reduce the flow below that level within 30 minutes, regardless of the results of Real-time Contingency analysis.

II. Purpose of Retirement of TOP-007-WECC-1a

The purpose of the proposed retirement of TOP-007-WECC-1a, along with the planned modifications to Peak's SOL methodology, is to move away from the historical Path SOL

paradigm, decoupling operating limits and transfer capability, and allow entities in the Western Interconnection to align their operating practices with the framework established in the revised TOP/IRO Reliability Standards approved in Order No. 817. As discussed below, the use of the Path OTC/SOL paradigm, unique to the Western Interconnection, has not always provided an optimal framework for reliably operating the BPS and is not necessary for reliable operations. As recognized in Order No. 817, the revised TOP/IRO Reliability Standards – which are focused on identifying SOLs and IROLs on a facility-by-facility basis (as opposed to an entire Transmission path) and using OPAs and RTAs to assess conditions and identify expected or actual SOL or IROL exceedances – provide a comprehensive approach to achieving the objective of operating within acceptable pre- and post-Contingency reliability criteria.[27] The retirement of TOP-007-WECC-1a and alignment with the continent-wide TOP/IRO Reliability Standards would help ensure that SOLs are developed for each BES facility that comprise the 40 applicable Transmission paths and that those SOLs (and any IROLs) accurately reflect Real-time operating limits. The retirement will also avoid duplication and potential confusion upon the effective date of the revised TOP/IRO standards stemming from the disparate operating paradigms reflected in TOP-007-WECC-1a and the revised TOP/IRO standards.

a. <u>The Operational Paradigm Reflected in TOP-007-WECC-1a Does Not Provide an Optimal Framework for Reliable Operations</u>

As noted above, given the analysis tools available at the time the RMS was first developed, the presumption was that operating within the Path OTC/SOL would result in acceptable system performance for the pre- and post-Contingency operating states and an efficient use of the Transmission system. That has not always been the case. The application of the Path SOL

[27] Order No. 817 at PP 16-17.

construct has not always resulted in Path SOL values that represented the appropriate limits for reliably operating the facilities comprising the Transmission paths given existing conditions (i.e., the Path SOL value did not provide for acceptable performance pre- and post-Contingency). As acknowledged in the joint FERC-NERC report titled *Arizona-Southern California Outage on September 8, 2011, Causes and Recommendations* (the "Southwest Outage Report"), the September 8, 2011 event in the Southwest occurred even though the facilities on the relevant Transmission paths were operated within their pre-determined Path SOLs.[28] While Transfer Capability values reflected in the Path SOL are appropriate for determining scheduling limitations, using these pre-determined Transfer Capability values as Real-time operating limits poses significant reliability gaps.

At the other end of the spectrum, the use of a pre-determined OTC/SOL for an entire path as contemplated under TOP-007-WECC-1a and Peak's SOL methodology has not always resulted in an efficient use of the Transmission system. There have been instances where actual flows exceeded the Path SOL and the requirements of TOP-007-WECC-1a necessitated that entities take extreme and disruptive actions to reduce the flow, such as pre-Contingency load shedding, even though Real-time analysis did not confirm the presence of an actual reliability issue. In such circumstances, TOP-007-WECC-1a prevented operators in the Western Interconnection from efficiently and reliably operating the system based on Real-Time analysis.

Following the Southwest Outage Report and with the proliferation of advanced applications, such as state estimation and Real-time Contingency analysis, entities in the Western Interconnection have come to understand that reliance on a single pre-determined Path SOL value

[28] FERC and NERC, *Arizona-Southern California Outage on September 8, 2011, Causes and Recommendations* (Apr. 27, 2012), at 99-100, *available at* http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.

may not always provide reasonable assurance of reliable operations. As a result and consistent with the findings and recommendations of the Southwest Outage Report, entities in the Western Interconnection have been making changes in their operating practices to improve reliability, including, among other things, increased reliance on day-ahead and Real-Time Assessments of operating conditions, and to differentiate between Real-time operating limits and transfer capability. As part of that transition, entities in the Western Interconnection are seeking to move away from the historical, path-centric paradigm unique to the Western Interconnection and align their practices with the framework in the revised continent-wide TOP/IRO Reliability Standards by, among other things, (1) modifying Peak's SOL methodology to establish SOLs for each BES Facility, not entire Paths, based on Facility Ratings, voltage limits, and stability limits, and (2) retiring regional Reliability Standard TOP-007-WECC-1a.[29]

b. The Revised TOP/IRO Standards Provide a More Efficient and Effective Framework for Operating the BPS Within Acceptable Pre- and Post-Contingency Criteria

In contrast to the operational paradigm in TOP-007-WECC-1a, as the Commission recognized in Order No. 817, the revised TOP/IRO Reliability Standards provide a "comprehensive framework as well as important improvements to ensure that the bulk electric system is operated within pre-established limits while enhancing situational awareness and strengthening operations planning."[30] Additionally, the Commission stated that the revised

[29] Entities in the Western Interconnection would continue to use Transfer Capability values that respect SOLs for purposes of scheduling transmission service but, for the reasons stated above, would no longer combine transfer limits and operating limits into a single, pre-determined value for measuring reliable operation on an entire Transmission path.

[30] Order No. 817 at 14.

TOP/IRO Reliability Standards "address the coordinated efforts to plan and reliably operate the bulk electric system under both normal and abnormal conditions."[31]

The continent-wide revised TOP/IRO Reliability Standards reflect, in large measure, the operating paradigm contemplated by the Southwest Outage Report.[32] The TOP/IRO Reliability Standards approved in Order No. 817 contemplate SOLs and IROLs as dynamic values reflecting Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, determined for each BES facility based on assessments of expected or actual conditions to ensure acceptable performance pre- and post-Contingency.[33] The use of a single pre-determined Path SOL value, as reflected in TOP-007-WECC-1a and Peak's current SOL methodology, is not consistent with the framework contemplated in the revised TOP/IRO Standards and exists only in TOP-007-WECC-1a as a legacy of an operating paradigm established in the late 1990s. As stated in the whitepaper titled "System Operating Limit Definition and Exceedance Clarification" (the "SOL Whitepaper") [34] underpinning the development of the revised TOP/IRO Reliability Standards:

> Some have interpreted the language in approved FAC-011-2, Requirement R2 to imply that the objective is to perform prior studies to determine a specific MW flow value (SOL) that ensures operation within the criteria specified in approved FAC-011-2, Requirement R2 sub-requirements, the assumption being that if the system is operated within this pre-determined SOL value, then all of the pre- and post-Contingency requirements described in approved FAC-011-2, Requirement R2 will be met. The SDT believes this approach may not capture the complete intent of the SOL concept within approved FAC-011-2, which is both:

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31 *Id*.

32 As the Commission recognized, the revisions to the TOP/IRO standards and the definitions of OPA and RTA addressed multiple recommendations in the Southwest Outage Report. Order No. 817 at P 17.

33 Order No. 817 at P 16 (recognizing that "the TOP/IRO Standards approved [in Order No. 817] address the possibility that additional SOLs could develop or occur in the same-day or Real-Time operational time horizon and, therefore, would pose an operational risk to the interconnected transmission network if not addressed.").

34 The SOL Whitepaper is available at http://www.nerc.com/pa/Stand/Prjct201403RvsnstoTOPandIROStndrds/2014_03_fifth_posting_white_paper_sol_exceedance_20150108_clean.pdf.

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.

> SOLs are based on Normal and Emergency (short-term) Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits – *any of which can be the most restrictive limit at any point in time pre- or post-Contingency*. For example, if an area of the BES is at no risk of encroaching upon Stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of Facility Ratings, then the thermal Facility Ratings in that area are the most limiting SOLs. Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the voltage limits in that area are the most limiting SOLs.[35]

Based on this understanding of SOLs, the TOP/IRO Reliability Standards approved in Order No. 817 set forth requirements for operating within SOLs and IROLs, focusing on the use of OPAs and RTAs to assess conditions and identify the relevant SOLs and IROLs for each BES facility and any expected or actual exceedances of those limits. Specifically, during the operations planning time horizon, Reliability Coordinators and Transmission Operators must perform OPAs to assess whether the planned operations for the next-day will exceed SOLs (and IROLs for the Reliability Coordinator) within their area.[36] If the OPA identifies any potential exceedances, the Reliability Coordinator and Transmission Operator must have an Operating Plan to address the exceedance.[37] In Real-time, Reliability Coordinators and Transmission Operators must perform RTA every 30 minutes to determine whether there are any expected or actual exceedances of SOLs (and IROLs for the Reliability Coordinator) based on Real-time conditions.[38] If the RTA identifies any such exceedances, the Reliability Coordinator and Transmission Operator must initiate its

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35 SOL Whitepaper at 3 (emphasis added).

36 IRO-008-2, Requirement R1; TOP-004-2, Requirement R1.

37 IRO-008-2, Requirement R2; TOP-004-2, Requirement R2.

38 IRO-008-2, Requirement R4; TOP-001-3, Requirement R13.

Operating Plan to mitigate the SOL exceedance.[39] If there is an expected or actual IROL exceedance identified in the RTA, the exceedance must be resolved within the IROL T_v, which can be no longer than 30 minutes.[40]

The WECC Path 30 (TOT 1A) example, discussed above, helps illustrate the need to retire TOP-007-WECC-1a. As described above, WECC Path 30 (TOT 1A) currently has a Path SOL of 650 MW for flows going east to west based on transfer studies indicating that a Contingency of the Bears Ears – Bonanza 345 kV line may cause the Hayden – Artesia 138 kV line to exceed its emergency Facility Rating at transfer levels exceeding 650 MW. As a result of these studies, the relevant entities in the Western Interconnection monitor for that Contingency in their Real-time Contingency analysis. If TOP-007-WECC-1a is not retired, Transmission Operators may be required to monitor the Bears Ears – Bonanza 345kV line Contingency under two conflicting paradigms.

Under the revised TOP/IRO Reliability Standards, Transmission Operators and Peak, as the Reliability Coordinator, would (1) perform OPAs and RTAs to determine, among other things, if conditions are such that the loss of the Bears Ears – Bonanza 345kV line were to cause the Hayden – Artesia 138 kV line to exceed its emergency Facility Rating and, (2) if so, take action to mitigate that SOL exceedance in accordance with the applicable Operating Plan. If the emergency Facility Rating for the Hayden – Artesia line were also designated as an IROL, the mitigating actions would have to occur with IROL T_v.

NERC understands that it is possible for Real-time Contingency analysis to show that even if flows on the Transmission path exceeded the 650 MW Path SOL, the expected or actual

[39] IRO-008-2, Requirement R5; TOP-001-3, Requirement R14.

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

operating conditions may be such that a Contingency of the Bears Ears – Bonanza 345kV line would not cause the Hayden – Artesia 138 kV line to exceed its emergency Facility Rating at the time. Conversely, NERC understands that it is also possible for Real-time Contingency analysis to show that even if flows were below the 650 MW Path SOL, the conditions may be such that a Contingency of the Bears Ears – Bonanza 345kV line would cause the Hayden – Artesia 138 kV line to exceed its emergency Facility Rating at the time. Under the revised TOP/IRO Reliability Standards, the assessment of conditions through OPAs and RTAs would show whether the SOL for the Hayden – Artesia 138 kV line would actually be exceeded as a result of the that Contingency and the relevant entities would be required to act to maintain reliability in their areas under Reliability Standards IRO-001-4, Requirement R1 and TOP-001-3, Requirement R1.

In contrast, under TOP-007-WECC-1a, the results of OPAs and RTAs are irrelevant. Should flows on WECC Path 30 (TOT 1A) exceed 650 MW, Transmission Operators must take action, up to and including load shedding, to reduce the flow below that level within 30 minutes, regardless of whether Real-Time Contingency analysis identifies an expected or actual exceedance of the emergency Facility Rating for the Hayden – Artesia 138 kV line. On the other hand, if Real-Time Contingency analysis identifies that such an SOL exceedance is expected to occur or is actually occurring in Real-time even if flows were below 650 MW, TOP-007-WECC-1a would not require any action because the Path SOL is not exceeded. In short, under TOP-007-WECC-1a, entities in the Western Interconnection may be required to take mitigating action (redispatching generation, curtailing schedules, and even shedding load) when Real-time tools indicate that no action is necessary. In other circumstances, TOP-007-WECC-1a would not require any mitigating

action when Real-time tools indicates a potential or actual reliability issue (i.e., the use of Path SOLs could sometimes mask actual reliability problems).[41]

Given the requirements in the revised TOP/IRO Reliability Standards, the question is whether there is any continuing reliability need to monitor and address the Bears Ears – Bonanza 345kV line Contingency under the TOP-007-WECC-1a paradigm and risk operator confusion as to the appropriate operating limit for Real-time operations. As the example above highlights, as compared to the legacy practices reflected in TOP-007-WECC-1a, the framework established in the revised TOP/IRO standards provides for a more efficient and accurate mechanism to identify and respond to potential reliability issues. As the Commission acknowledged in Order No. 817 and as discussed in greater in the following sections, the revised TOP/IRO Reliability Standards "provide *a comprehensive framework*…to ensure that the bulk electric system is operated within pre-established limits while enhancing situational awareness and strengthening operations planning."[42] There is no reliability need to continue the historical, path-centric approach reflected in TOP-007-WECC-1a or to treat the facilities comprising the 40 Transmission paths subject to TOP-007-WECC-1a any differently than all other facilities are treated under the continent-wide TOP/IRO Reliability Standards. Each of the facilities comprising the 40 Transmission paths would be monitored in accordance with the Commission-approved TOP/IRO Reliability Standards and subject to associated mitigation requirements should there be an expected or actual exceedance of an SOL or IROL on those facilities.

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[41] Of course, if Real-time analysis indicates a potential or actual reliability issue, Transmission Operators would take action to address the issue, in accordance with the continent-wide standards.

[42] Order No. 817 at 14 (emphasis added).

III. Application of the Revised TOP/IRO Reliability Standards to the 40 Transmission Paths

The remainder of this Supplement discusses manner in which the reliability of the 40 Transmission paths currently subject to TOP-007-WECC-1a is addressed under the revised TOP/IRO Reliability Standards. This section is organized as follows:

- Section III.a explains the manner in which the 40 Transmission paths subject to TOP-007-WECC-1a would be monitored under the continent-wide TOP and IRO Reliability Standards.
- Section III.b discusses whether the 30-minute mitigation requirement in TOP-007-WECC-1a would continue to apply to the 40 Transmission paths following retirement.
- Section III.c discusses the manner in which SOLs and IROLs are established for each of the facilities comprising the 40 Transmission paths and the types of limitations associated with those paths.
- Section III.d discusses Peak's intent to modify its methodology for establishing SOLs and IROLs and the manner in which such revisions could impact the evaluation of the 40 Transmission paths.
- Section III.e discusses Peak's use of a 1000 MW threshold in its current methodology for determining IROLs and its application to the 40 Transmission paths.

a. Each of the Facilities Comprising the 40 Transmission Paths Must be Monitored Under the Continent-wide TOP/IRO Reliability Standards to Help Ensure Reliable Operation

Upon the retirement of regional Reliability Standard TOP-007-WECC-1a and the modifications to Peak's SOL methodology, Transmission paths in the Western Interconnection would no longer have a single, uniquely monitored Path SOL.[43] Instead, each facility comprising the 40 Transmission paths would be separately monitored in accordance with the requirements in the continent-wide TOP-IRO Reliability Standards. With respect to monitoring those facilities, the TOP/IRO Reliability Standards affirmatively obligate Transmission Operators and Reliability

[43] The only exception would be if the Transmission path is directly associated with an identified and monitored stability limit.

Coordinators to monitor facilities in their areas to ensure they have the necessary situational awareness to maintain reliable operations, as follows:

- TOP-001-3, Requirement R10 requires each Transmission Operator to perform the following as necessary for determining SOL exceedances within its Transmission Operator Area: (1) within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and (2) outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.

- IRO-002-4, Requirement R11 obligates Reliability Coordinators to monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any SOL exceedances and to determine any IROL exceedances within its Reliability Coordinator Area.

With two exceptions, the facilities comprising each of the 40 paths subject TOP-007-WECC-1a are designated as BES facilities.[44] Under IRO-002-4, Requirement R11, the Reliability Coordinator is responsible for monitoring both BES Facilities and non-BES facilities that have an impact on the BES. Further, in accordance with directives in order No. 817, NERC is developing modifications to TOP-001-3, Requirement R10 to require Transmission Operators to also monitor non-BES facilities that could adversely impact BPS reliability. Accordingly, each of the facilities comprising the 40 Transmission paths, including non-BES facilities, would be subject to these monitoring requirements to ensure, among other things, that the facilities are operated within their SOLs and IROLs. In addition, as discussed above, the facilities comprising the 40 Transmission paths would be evaluated in OPAs and RTAs.[45]

To ensure that Reliability Coordinators and Transmission Operators have the data necessary to perform their OPAs, RTAs, and Real-time monitoring obligations, the TOP/IRO

[44] The two facilities that do not meet the BES definition are (1) Dry Gulch 115/69-kV transformer – Path 6 – West of Hatwai, and (2) Drum-Summit 60-kV line – Path 24 – PG&E-Sierra.

[45] In performing OPAs and RTAs, entities must consider the following inputs: 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

Reliability Standards (IRO-010-2 and TOP-003-3) establish requirements for the provision of information and data, including non-BES data, needed by Transmission Operators and Reliability Coordinators to fulfill their planning and operational responsibilities. Under Reliability Standards IRO-008-2 and TOP-003-3, Reliability Coordinators and Transmission Operators would collect information and data pertaining to the facilities comprising the 40 Transmission paths to help maintain situational awareness and reliable operations.

b. Each of the Facilities Comprising the 40 Transmission Paths Would be Subject to Mitigation Requirements under the Continent-wide TOP and IRO Reliability Standards Designed to Ensure Reliable Operations

Regional Reliability Standard TOP-007-WECC-1a establishes a 30-minute mitigation period for all exceedances of Path SOLs, regardless of risk to the BPS. As described above, the application of the 30-minute mitigation requirement to all Path SOLs is a legacy of the RMS program.[46] WECC is not aware of any specific technical studies or analysis supporting application of the 30-minute mitigation time to each Path SOL; instead, the 30-minute period seems to have originated as an agreement between participants in the RMS that 30 minutes represents a reasonable amount of time to require Transmission Operators to return flow on the path to within the Path OTC/SOL.

In contrast, the revised TOP/IRO Reliability Standards do not create a uniform timeframe for addressing all SOL or IROL exceedances; instead, those standards create a risk-based framework for addressing SOL and IROL exceedances. As discussed below, depending on risk to the BPS, the required mitigation period could be less than 30 minutes and, in other cases, be greater than 30 minutes.

[46] As discussed above, the RMS originally required mitigation within 20 minutes for stability limited paths or for more than 30 minutes for thermally limited paths. The mitigation timeframe was modified to 30 minutes for all Path SOLs with the approval of TOP-007-WECC-1a.

The revised TOP/IRO Reliability Standards establish the following requirements in the day-ahead time frame for mitigating potential SOL and IROL exceedances:

- Each Transmission Operator is required to conduct an OPA to assess whether its planned operations for the next day will exceed any of its SOLs. (TOP-001-3, Requirement R1).

- Similarly, each Reliability Coordinator is required to conduct an OPA to assess whether its planned operations for the next day will exceed any SOLs and IROLs within its Wide Area. (IRO-008-2, Requirement R1).

- If the Transmission Operator's OPA identifies any potential SOL exceedances, the Transmission Operator must: (1) have an Operating Plan to mitigate that exceedance; (2) notify entities identified in the Operating Plan as to their role under those plans; and (3) provide its Operating Plan for next-day operations to its Reliability Coordinator. (TOP-001-3, Requirements R2, R3 and R6). The Operating Plan must include specific plans/strategies to prevent an SOL exceedance (i.e., pre-Contingency actions) or mitigate the impact of the SOL exceedance (i.e., post-Contingency actions). The Operating Plan must contain appropriate timeframes for initiating the actions required under the plan to maintain reliable operations and/or return the system to within applicable SOLs.

- If the Reliability Coordinator's OPA identifies any potential SOL or IROL exceedances, the Reliability Coordinator must: (1) have a coordinated Operating Plan for next day operations to address the potential exceedances, which considers the Operating Plans provided by its Transmission Operators; and (2) notify other impacted entities of their role under the plan. (IRO-008-2, Requirements R2 and R3).

- Additionally, for each IROL that the Reliability Coordinator identifies one or more days prior to the operating day, the Reliability Coordinator must have one or more Operating Processes, Procedures, or Plans that identify actions the Reliability Coordinator shall take or actions the Reliability Coordinator shall direct others to take (up to and including load shedding) that can be implemented in time to prevent the identified IROL exceedance and to mitigate the magnitude and duration of an IROL exceedance such that the IROL exceedance is relieved within the IROL's T_v, which is defined as the maximum time, not to exceed 30 minutes, that an IROL can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. (IRO-009-2, Requirement R1).

For the operating day, the revised TOP/IRO Reliability Standards establish the following requirements for mitigating expected or actual SOL and IROL exceedances:

- Each Transmission Operator must perform an RTA every 30 minutes to assess conditions and determine whether there are any actual or expected SOL exceedances. (TOP-001-3, Requirement R13).

- The Reliability Coordinator must also perform an RTA every 30 minutes to assess conditions and determine whether there are any actual or expected SOL or IROL exceedances. (IRO-008-2, Requirement R4).

- If the results of its RTA indicates an actual or expected condition that results in, or could result in, a SOL or IROL exceedance within its Wide Area, the Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan. (IRO-008-2, Requirement R5).

- Further, the Transmission Operator must initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or RTA and inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. (TOP-001-3, Requirement R1).

- Given the more severe impact of IROL exceedances, the Transmission Operator is prohibited from operating outside any IROL for a continuous duration exceeding its associated IROL T_v. (TOP-001-3, Requirement R1).

- Additionally, for expected or actual IROL exceedances identified through its Real-time monitoring or RTA, the Reliability Coordinator must (1) initiate one or more Operating Processes, Procedures, or Plans to prevent an expected IROL exceedance; and (2) act or direct others to act so that the magnitude and duration of an actual IROL exceedance is mitigated within the IROL's T_v. (IRO-009-2, Requirements R2 and R3).

Under this framework, the applicable mitigation period depends on whether the SOL is also designated as an IROL and the facts and circumstances presented by the exceedance. Given the increased severity of adverse reliability impact of an IROL exceedance, the maximum period allowed for operating outside an IROL is 30 minutes, as described above. The application of IROL T_v, however, could result in a mitigation period of less than 30 minutes as, in some cases, the risk to the Interconnection or other Reliability Coordinator Areas would become greater than acceptable within 5-10 minutes of the IROL exceedance or even immediately. As such, under the Revised TOP/IRO Reliability Standards, upon the retirement of TOP-007-WECC-1a, if any facilities comprising the 40 applicable Transmission paths has an IROL, the mitigation period for exceedances of that IROL would be equivalent to the time provided in TOP-007-WECC -1a for Path SOL exceedances, if not less.

For (non-IROL) SOL exceedances, the revised TOP/IRO Reliability Standards recognize that a maximum mitigation period applicable to all SOL exceedances is not necessary or prudent as the mitigation period should depend on the potential impact of that exceedance over time. The TOP/IRO Reliability Standards thus provide Reliability Coordinators and Transmission Operators the flexibility to determine the appropriate mitigation time periods. As described above, when there is an SOL exceedance in Real-time, the Transmission Operator is required to implement mitigating strategies consistent with its Operating Plan. Operating Plans can include specific Operating Procedures or more general Operating Processes and should include both pre- and post-Contingency mitigation plans/strategies. As described in the SOL Whitepaper, Operating Plans must include appropriate timelines to escalate the level of mitigating plans/strategies to ensure acceptable BES performance is maintained and prevent SOL exceedances from becoming an IROL exceedance.[47] As such, an Operating Plan must include the appropriate time element to return the system to within acceptable Normal and Emergency (short-term) Ratings and/or operating limits.

The timeframes set forth in the Operating Plan could require action in less than 30 minutes or greater than 30 minutes, depending on the facts and circumstances. For instance, depending on the time-value rating of the facility, the Operating Plan could lay out certain actions to be taken prior to the exceedance, within five minutes of the exceedance, and within 30 minutes, within 60 minutes if the problem was not resolved. Ultimately, however, Reliability Standards IRO-001-4, Requirement R1 and TOP-001-3, Requirement R1 create affirmative obligations for Reliability Coordinators and Transmission Operators, respectively, to act to maintain the reliability of their area via their own actions or by issuing Operating Instructions. As a result, should an entity's

[47] SOL Whitepaper at 7-8.

Operating Plan fail to require action in timely manner so as to maintain reliability in its area, it risks violating those requirements.

Upon the effective date of the revised TOP/IRO Standards and the retirement of TOP-007-WECC-1a, Reliability Coordinators and Transmission Operators would be subject to these mitigation requirements for all BES facilities in the Western Interconnection, including those comprising each of the 40 Transmission paths currently subject to TOP-007-WECC-1a. Additionally, under the FAC Reliability Standards, Peak, as the Reliability Coordinator for the Western Interconnection (except Alberta, Canada), is obligated to determine which SOLs for the facilities comprising the 40 Transmission paths, as well as any others in the Western Interconnection, would meet the criteria for an IROL designation such that a maximum 30-minute time period would continue to apply to those facilities upon the retirement of TOP-007-WECC-1a. Any failure to properly designate IROLs may be a violation of requirements in the FAC Reliability Standard (FAC-014-2).

In deciding to move away from the historical approach reflected in TOP-007-WECC-1a, WECC did not identify any reliability need to continue the Path SOL paradigm and treat the facilities comprising the 40 applicable Transmission paths any differently from any other BES facility. The 40 paths subject to TOP-007-WECC-1a were originally selected for different treatment as part of the RMS in the late 1990s. There are no records of any technical studies or analysis to document the criteria under which the paths were chosen for inclusion in the RMS. The identification of the 40 Transmission paths seems to have been an attempt to capture many of the high-voltage transmission lines between the historical WSCC control areas. Similarly, as noted above, application of the 30-minute mitigation period to all exceedances of Path SOLs seems to

be a remnant of an agreement as to a reasonable, uniform time period for mitigating action rather than an analysis of the reliability effects of such exceedances.

c. SOLs and IROLs, Where Applicable, Must be Established for Each of the Facilities Comprising the 40 Transmission Paths in Accordance with Peak's SOL Methodology

As described above, under the revised TOP/IRO Reliability Standards, all BES facilities must be operated within SOLs and, as applicable, IROLs. In accordance with the requirements of the FAC Reliability Standards, Transmission Operators must, consistent with their Reliability Coordinator's SOL methodology, establish SOLs for each of their BES facilities. Additionally, the Reliability Coordinator must determine which of those SOLs warrant designation as an IROL. As contemplated in the FAC and TOP/IRO standards, SOLs and IROLs are determined based on seasonal studies, outage coordination studies, OPAs, and RTAs. As noted above, certain SOL values are dynamic, reflecting changing operating conditions. Similarly, an SOL may become an IROL when certain conditions are present but not under other conditions.

As contemplated in Peak's document outlining expected modifications to its SOL methodology ("Draft SOL Methodology Document"), posted to its website on September 9, 2016, all BES Facilities in the Western Interconnection, including those that comprise the 40 Transmission paths currently subject to TOP-007-WECC-1a, would be monitored in the operations time horizon for pre- and post-Contingency performance in an iterative fashion as Real-time approaches: first via seasonal assessments, then through the IRO-017 outage coordination process studies, followed by OPAs, and finally through RTAs.[48] For each of these iterative steps, Transmission Operators will determine whether Facility Ratings or system voltage limits would be expected to be exceeded in the pre- or post-Contingency state, or whether any instability risks

[48] The Draft SOL Methodology Document is available at: https://www.peakrc.com/whatwedo/sol/Pages/default.aspx.

would need to be addressed via established stability limits. In studying the system and assessing conditions for determining SOLs, Transmission Operators would be responsible under Peak's expected SOL methodology for stressing the system, identifying any instability risks, and determining the extent to which transmission interfaces and load areas should be stressed in identifying stability SOLs. Although the extent to which the system should be stressed depends on a variety of factors, to accurately determine stability SOLs, the system should be stressed up to, and slightly beyond, reasonable maximum stressed conditions. Any stability limitation that results from studies would be identified as an SOL.

Peak's SOL Methodology would then be applied to determine whether any of the SOLs qualify as an IROL. NERC understands that Peak currently monitors three IROLs in its area and is continuously performing studies to identify other limits that may qualify as IROLs. Peak reviews studies performed by Planning Coordinators, seasonal studies performed by sub-regional study groups, and outage studies and OPAs performed by Transmission Operators to determine the existence of IROLs. Peak also collaborates with Transmission Operators to identify additional risks in the system for instability or potential Cascading in Real-time operations. If any of these analyses reveals risks associated with instability, Cascading, or uncontrolled separation, these risks would be addressed via IROLs as appropriate per Peak's SOL Methodology.

As it relates to establishing SOLs and IROLs, Peak conducted an examination of the 40 Transmission paths to understand and document the type of limitation associated with each of the paths. Attachment A hereto provides the results of that investigation so as to provide the Commission additional information about the 40 Transmission paths and the types of issues entities in the Western Interconnection currently monitor. The information in Attachment A is based on data from planning studies that established the WECC Path Rating and Transmission

Operator reports since January 2015. Peak noted that the limitations on these paths change based on Transmission Operator assessments of anticipated operating conditions, including Facility outages. Peak's objective in gathering this information was to identify paths that were flagged as being transient stability limited or voltage stability limited since January 1, 2015 and for use in its determinations of whether any of these limitations warrant an IROL designation going forward.

The following are some key observations from the data in the attachment:

- Of the 40 Transmission paths, only two were identified as being limited by transient stability or voltage stability. One of the two stability limits has already been designated as an IROL (i.e., the NW Washington IROL).
- 25 Transmission paths are thermally limited.
- 15 of the Transmission paths are thermally based proxy limits (i.e., limitations placed on the path to address a post-Contingency thermal limit exceedance on a non-Path Facility).
- Three of the Transmission paths are limited by steady state voltage, voltage dip criteria, or voltage deviation.
- Six of the Transmission paths are combinations of thermally limited or voltage limited depending on either direction of flow or season.
- The limitation on 16 Transmission paths is established by multiple contingency events.

d. <u>The Expected Modifications to Peak's SOL Methodology are Designed to Enbsure that SOLs and IROLs are Developed Consistent with the Framework Established in the Revised TOP/IRO Standards</u>

As noted in the Petition, NERC and WECC understand that Peak expects to issue a revised SOL methodology as part of the transition away from the path-centric paradigm, with an effective date of April 1, 2017. The April 1, 2017 effective date is designed to coincide with the effective date of the revised TOP/IRO Reliability Standards. Consistent with the proposed retirement of TOP-007-WECC-1a, under the revised SOL methodology, NERC and WECC understand that SOLs for the 40 Transmission paths subject to TOP-007-WECC-1a will no longer reflect a single pre-determined value for the entire path. Instead, as discussed above, the SOL methodology would

focus on determining SOLs on a facility-by-facility basis and reflect Facility Ratings, system voltage limits, and stability limitations used in operations.

Peak's Draft SOL Methodology Document describes the manner in which BES facilities in the Western Interconnection, including facilities comprising the 40 Transmission paths will be evaluated for SOL and IROL designations. As discussed therein and as noted above, for stability limitations, Transmission Operators are required to stress the system to determine the existence of any stability limitations. When stability limitations are established, they must be established in a manner that most accurately and directly addresses the instability risk, and they must be established on an interface that most accurately and directly monitors the instability risk. Accordingly, stability limitations may or may not coincide with defined WECC Paths. Neither historical presumptions/practices regarding system monitoring nor commercial/contractual arrangements should influence where stability limitations are most accurately established and monitored for reliability. Additionally, Facility Ratings and system voltage limits will be monitored for the pre- and post-Contingency state as SOLs, and any identified stability limitations will be monitored as SOLs (or IROLs, if applicable).

e. The Expected Modifications to Peak's SOL Methodology Would Eliminate the 1,000 MW Threshold for Determining IROLs

As the Commission noted in Order No. 817, Peak's SOL methodology currently includes a 1,000 MW threshold as part of its IROL determinations.[49] NERC and WECC understand that as part of its modifications to its SOL methodology, Peak expects to remove the 1,000 MW criteria. NERC and WECC understand that Peak's revised SOL methodology would contain a description of instability, Cascading, and uncontrolled separation that necessitate the need to establishing an

[49] Order No. 817 at P 27.

SOL as an IROL without use of a load loss threshold. Accordingly, the 1,000 MW threshold would not be applied to the facilities comprising the 40 Transmission paths upon the issuance of the modified SOL methodology, which is expected to occur on the proposed effective date of the new TOP/IRO Reliability Standards and the proposed retirement of TOP-007-WECC-1a. In any event, the specifics related to Peak's SOL methodology and the appropriate designation of IROLs is a matter of compliance with Reliability Standard FAC-011-2 and should not affect the Commission's analysis of whether regional Reliability Standard TOP-007-WECC-1a should be retired.

IV. Conclusion

For the reasons discussed in the Petition and in this Supplement, NERC and WECC respectfully request that the Commission approve retirement of regional Reliability Standard TOP-007-WECC-1a, effective April 1, 2017.

Respectfully Submitted

/s/ Shamai Elstein

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Counsel for the North American Electric Reliability Corporation

Date: November 16, 2016

Attachment A

PEAKRELIABILITY
assuring the wide area view

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Peak Reliability performed an investigation of each of the paths listed in the TOP-007-WECC-1a “Major WECC Transfer Paths in the Bulk Electric System”. The investigation examined the 2016 WECC Path Rating Catalog as well as TOP-provided Path Reports submitted since January 1, 2015. The objective of this investigation was to understand and document the type of limitation associated with each of the TOP-007-WECC-1a Paths.

The WECC Path Rating Catalog provides a description of the type of limitation associated with each path based on the planning studies that established the WECC Path Rating.

Per Peak’s current SOL Methodology for the Operations Horizon and Peak’s IRO-010 Data specification, TOPs are required to provide Peak with a daily Path Report for each of the WECC Paths, including the TOP-007-WECC-1a Paths. The Path Report identifies the type of limitation for each path (thermal, voltage, transient stability, voltage stability) and any relevant transmission or generation facility outage that is associated with that limitation. The limitation on these Paths change frequently based on TOP assessments of anticipating operating conditions, including Facility outages. Peak’s objective was to identify Paths that were flagged as being transient stability limited or voltage stability limited since January 1, 2015.

The results of the investigation are captured in the attached spreadsheet. A few key observations can be gleaned from the data:

1. Of the 40 Paths listed in the “Major WECC Transfer Paths in the Bulk Electric System”, only two Paths were identified as being limited by transient stability or voltage stability. One of the two stability limited Paths is addressed via the NW Washington IROL currently in place.
2. Twenty seven Paths are strictly thermally limited.
3. Fifteen of the Path limitations are thermally based proxy limits – these are limitations placed on the Path to address a post-Contingency thermal limit exceedance on a non-Path Facility.
4. Three Paths are limited by steady state voltage, voltage dip criteria, or voltage deviation.
5. Six Paths are combinations of thermally limited or voltage limited depending on either direction of flow or season.
6. Sixteen Paths have the limit established by multiple contingency events.

Peak's next steps are to perform a more thorough investigation of Path 1 which is limited by frequency performance within AESO. Peak will collaborate with the TOPs associated with that Path to determine if an IROL should be established.

Peak intends to continue to monitor all BES Facilities for pre- and post-Contingency performance as part of its Operational Planning Analyses (OPA) and Real-time Assessments (RTA). Under the new Reliability Standards, TOPs are required to do the same. Any SOL exceedance identified in a TOP or RC OPA is required to have an Operating Plan to address the SOL exceedance. Additionally, any SOL exceedance identified in an RTA is required to have an Operating Plan implemented to address that SOL exceedance. Peak intends to continue using the Operating Guides that were collaboratively developed for each WECC Path. These Path Operating Guides provide RC System Operators and TOP System Operators with steps that can be taken when flow on the path is causing or contributing to an SOL Exceedance.

The IRO-017-1 Outage Coordination process (final version posted on 10/03/2016) requires that each TOP identify any instability risks that arise as a result of the outage conditions. If any new instability risks arise due to the outage, the TOP is responsible for establishing outage-specific stability limits and communicating the instability risk, stability limits and any associated Operating Plans to the RC. Peak will investigate each stability limitation and will apply its SOL Methodology to determine whether the stability limitation qualifies as an IROL.

TOP-007-WECC-1a Path?	Path Name	Path Operator	Limiting Facility Part of Path	Path Limitation	Associated Contingency(ies)
1	Alberta - British Columbia	AESO, BCHA	on	E-W: AESO frequency performance critierion W-E: thermal	E-W Loss of Cranbrook-Bennett 500kV tie violates AESO frequency performance criteria W-E Loss of generation within AESO
3	Northwest - British Columbia	BCHA	on	thermal	Loss of Custer-Ingldow 1 & 2 and separation of BCHydro
4	West of Cascades - North	BPA	stability	voltage-stability limited, thermal (voltage stability limit monitored by NW Washington IROL)	Schultz-Raver #1 500kV & Schultz-Echo Lake #1 500kV
5	West of Cascades - South	BPA	off	thermal summer low voltage in winter	John Day-Marion & Buckley-Marion 500kV or Ashe-Marion & Buckley-Marion 500kV
6	West of Hatwai	BPA	off	thermal	Bell-Coulee 500kV & Westside-Coulee 230kV or breaker failure @Taft 500kV4
8	Montana-to-Northwest	NWMT	on	E-W thermal W-E. pre contingency voltage	Garrison-Taft #1&2 500kV
14	Idaho-to-Northwest	IPCO	on	thermal	Hemingway-Summer Lake 500kV or Lolo-Oxbow 230kV & Hells Canyon-Brownlee 230kV
15	Midway - Los Banos	CISO	off	thermal	Midway-Gates & Midway-Lost Banos 500kV or 2 Palo Verde Units or Los Banos-Tesla & Los Banos Tracy 500kV or Tesla-Midway 1&2 500kV
16	Idaho - Sierra	SPPC	off	thermal	Humboldt-Coyote Creek 345kV or Coyote Creek-Valmy (S-N)
17	Borah West	IPCO	on	thermal	Kinport-Midpoint & Borah-Adelaide-Midpoint #1 345kV
18	Montana-Idaho	NWMT	on	thermal and voltage limited	Bridger-Three-Mile Knoll & Bridger-Populus 345kV (N-S) or Brady-Antelope 230kV (S-N)
19	Bridger West	PAC	on	thermal limit, voltage dip and frequency dip criterion	Jim Bridger-Populus #1 or #2 345kV
20	Path C (Pre-Gateway)	PAC	N/A	voltage	Simultaneous loss of any 2 Path 19 lines
22	Southwest of Four Corners	APS	on	thermal	Four Corners-Moenkopi 500kV line or either Four Corners-Cholla 345kV lines
24	PG&E - Sierra	CISO	on	thermal	Drum PH or Drum-Rio Oso #1 115kV or Drum Summit 1&2 115kV or Goldhill-Placer #2 115kV or Halsey Jct-Newark #1&2 115kV
26	Northern-Southern California	CISO	on	thermal	Midway-Vincent #1&2 500kV or Midway-Vincent #1 & Whirlwind-Midway 500kV
27	Intermountain Power Project DC	LADWP	off	thermal or post contingency voltage deviation	Loss of the IPPDC bi-pole line.
30	TOT 1A	WACM	on	thermal	Craig-Bonanza 345kV
31	TOT 2A	WACM	off	thermal	Montrose-San Juan 345kV
32	Pavant - Gonder 230kV; Intermountain-Gonder 230kV	SPPC	off	thermal	IPP-Gonder 230kV (E-W) or Robinson-Gonder 345kV (W-E)
34	(Paths 78 and 79)	PACE	off	thermal	Sigurd-Three Peaks 345 or Three Peaks-Red Butte 345
35	TOT 2C	NEVP	on	thermal	Simultaneous Intermountain-Adelanto DC line outage
36	TOT 3	WACM	on	thermal	TOT 3 operating matrix; limiting contingencies vary
39	TOT 5	WACM	off	thermal	Hayden-Gore Pass 230kV or Craig-Ault 345kV or Hayden-Foidel Creek 230kV
45	SDG&E - CFE	CISO	on	thermal	Imperial Valley-Miguel 500kV
46	West of Colorado River	CISO	off	thermal	Imperial Valley North Gila 500kV or Palo Verde-Colorado River 500kV
47	Southern New Mexico (NM1)	EPEC	N/A	voltage	Springerville-Macho Springs 345kV or West Mesa-Arroyo 345kV or Greenlee-Hidalgo 345kV
48	Northern New Mexico	PNM	on	thermal	Four Corners-Rio Puerco 345kV or San Juan-Rio Puerco 345kV
49	East of the Colorado River	APS	on	thermal	Navajo-Crystal 500kV or Perkins-Mead 500kV or North Gila-Imperial Valley 500kV
50	Cholla - Pinnacle Peak	APS	off	thermal	Four Corners-Cholla 345kV
51	Southern Navajo	APS	off	thermal	Yavapai-Westwing 500kV
55	Brownlee East	IPCO	on	thermal	Hemingway-Summer Lake 500kV or two Jim Bridger 345kV lines or any two Brownlee-Boise Bench 230kV lines
61	Lugo - Victorville 500kV	CISO	on	thermal	Mohave-Lugo 500kV or Eldorado-Lugo 500kV
65	Pacific DC Intertie (PDCI)	LADWP	off	thermal	Loss of PDCI bi-pole line
66	California-Oregon Intertie (COI)	CISO	on	thermal	Malin Round Mt 1 & 2
73	North of John Day	BPA	off	ALIS stressed to reasonability limits with no limitation found	Two Palo Verde Units or PDCI Bi-pole
76	Alturas Project	SPPC	off	N-S post disturance voltage deviation Malin-Hilltop 230kV system S-N thermal	N-S Midpoint-Humboldt 345kV
80	Montana Southeast	NWMT	on	thermal	Broadview-Garrison #1&2 500kV
SCIT		CAISO	N/A	ALIS stressed to reasonability limits with no limitation found	Tested to reasonability limit with no issues identified
COI/PDCI – North of John Day cutplane		BPA	N/A	ALIS stressed to reasonability limits with no limitation found	Loss of two Palo Verde units

20161028-3031 FERC PDF (Unofficial) 10/28/2016

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD16-9-000

October 28, 2016

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Candice Castaneda
Counsel for North American Electric Reliability Corporation

Reference: Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard COM-001-3

Dear Mr. Elstein:

On August 15, 2016, the North American Electric Reliability Corporation (NERC) filed a petition for Commission approval, pursuant to section 215(d)(1) of the Federal Power Act (FPA)[1] and Section 39.5 of the Commission's regulations[2], of proposed revised Reliability Standard COM-001-3 (Communications). NERC also seeks approval of the associated implementation plan, the retirement of the currently-effective Reliability Standard COM-001-2.1, and the Violation Risk Factors and Violation Severity Levels associated with new Requirements R12 and R13 proposed in Reliability Standard COM-001-3.

NERC states in its petition that the proposed revised Reliability Standard COM-001-3 "revises Reliability Standard COM-001-2.1 pursuant to the Commission's directive in Order No. 808, by adding new Requirements R12 and R13 to expressly require applicable entities to have internal Interpersonal Communication capabilities for

[1] 16 U.S.C. § 824o (2012).

[2] 18 C.F.R. § 39.5 (2016).

20161028-3031 FERC PDF (Unofficial) 10/28/2016

the exchange of information necessary for the Reliable Operation of the BES.[3]" NERC states that "[t]he proposed Requirements would ensure that Reliability Standard COM-001-3 clearly address internal Interpersonal Communications capabilities that could involve the issuance or receipt of Operating Instruction or other communication that could impact reliability. This would include, for example, internal Interpersonal Communications capabilities for control centers within the same functional entity (including geographically separate control centers) and/or between a control center and field personnel."[4]

NERC's filing was noticed on August 15, 2016, with interventions, comments and protests due on or before September 14, 2016. No interventions, comments or protests were received.

NERC's uncontested petition is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2016), effective as of July 1, 2016.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713 (2016).

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

[3] NERC petition at 10.

[4] *Id* at 12.

Document Content(s)

RD16-9-000.DOCX.....1-2

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
North American Electric Reliability
Corporation
Docket No. RR16-5-000

November 4, 2016

North American Electric Reliability Corporation
1325 G Street NW, Suite 600
Washington, DC 20005

Attention: Candice Castaneda
Counsel for North American Electric Reliability Corporation

Reference: Rules of Procedure

Dear Ms. Castaneda:

On August 15, 2016, North American Electric Reliability Corporation (NERC) submitted proposed revisions to the NERC Rules of Procedure. Specifically, NERC proposes to revise Appendix 2, Appendix 5A, and Appendix 5B of the NERC Rules of Procedure to incorporate the terms Frequency Response Sharing Group and Regulation Reserve Sharing Group into the NERC Rules of Procedure, consistent with the terms as defined in the Glossary of Terms Used in NERC Reliability Standards and used in Reliability Standards BAL-00-1.1 and BAL-001-2.

Notice of this filing was issued on August 15, 2016, with protests and interventions due on or before September 6, 2016. Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure. 18 C.F.R. § 385.214. No protest was filed.

NERC's uncontested filing is accepted pursuant to the relevant authority delegated to the Director, Office of Energy Market Regulation, under 18 C.F.R. § 375.307.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or

procedures pursuant to 18 C.F.R. § 375.307(a)(2)(vi). This action does not constitute approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service provided for in the filed documents. Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order pursuant to 18 C.F.R. § 385.713.

Sincerely,

Penny S. Murrell, Director
Division of Electric Power Regulation-Central

157 FERC ¶ 61,122
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM16-6-000]

Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response

(Issued November 17, 2016)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to revise its regulations to require all newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install and enable primary frequency response capability as a condition of interconnection. To implement these requirements, the Commission proposes to revise the *pro forma* Large Generator Interconnection Agreement (LGIA) and the *pro forma* Small Generator Interconnection Agreement (SGIA). The proposed changes are designed to address the increasing impact of the evolving generation resource mix and to ensure that the relevant provisions of the *pro forma* LGIA and *pro forma* SGIA are just, reasonable, and not unduly discriminatory or preferential. The Commission also seeks comment on whether its proposals in this Notice of Proposed Rulemaking are sufficient at this time to ensure adequate levels of primary frequency response, or whether additional reforms are needed.

DATES: Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**

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

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

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

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SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response	Docket No. RM16-6-000

NOTICE OF PROPOSED RULEMAKING

(Issued November 17, 2016)

1. In this Notice of Proposed Rulemaking (NOPR), the Federal Energy Regulatory Commission (Commission) proposes to modify the *pro forma* Large Generator Interconnection Agreement (LGIA) and the *pro forma* Small Generator Interconnection Agreement (SGIA), pursuant to its authority under section 206 of the Federal Power Act (FPA) to ensure that rates, terms and conditions of jurisdictional service remain just and reasonable and not unduly discriminatory or preferential.[1] The proposed modifications would require all new large and small generating facilities, including both synchronous and non-synchronous, interconnecting with a LGIA or SGIA to install, maintain and operate equipment capable of providing primary frequency response as a condition of interconnection. The Commission also proposes to establish certain operating requirements, including maximum droop and deadband parameters in the *pro forma* LGIA and *pro forma* SGIA. The Commission does not propose to apply these requirements to generating facilities regulated by the Nuclear Regulatory Commission.

[1] 16 U.S.C. 824e (2012).

In addition, the Commission does not propose in these reforms to impose a headroom requirement for new generating facilities. The Commission also does not propose to mandate that new generating facilities receive any compensation for complying with the proposed requirements in this NOPR.

2. The proposed revisions address the Commission's concerns that the existing *pro forma* LGIA contains limited primary frequency response requirements that apply only to synchronous generating facilities and do not account for recent technological advancements that have enabled new non-synchronous generating facilities to now have primary frequency response capabilities. Further, the Commission believes that it may be unduly discriminatory or preferential to impose primary frequency response requirements only on new large generating facilities but not on new small generating facilities, and the reforms proposed here would impose comparable primary frequency response requirements on both new large and small generating facilities.

3. In addition, and as discussed below in paragraph 57, the Commission also seeks comment on whether its proposals in this NOPR are sufficient at this time to ensure adequate levels of primary frequency response, or whether additional reforms are needed.

4. The Commission seeks comment on the proposed reforms and requests for comment sixty (60) days after publication of this NOPR in the *Federal Register*.

I. Background

A. Frequency Response

5. Reliable operation of an Interconnection[2] depends on maintaining frequency within predetermined boundaries above and below a scheduled value, which is 60 Hertz (Hz) in North America. Changes in frequency are caused by changes in the balance between load and generation, such as the sudden loss of a large generator or a large amount of load. If frequency deviates too far above or below its scheduled value, it could potentially result in under frequency load shedding (UFLS), generation tripping, or cascading outages.[3]

6. Mitigation of frequency deviations after the sudden loss of generation or load is driven by three primary factors: inertial response, primary frequency response, and secondary frequency response.[4] Primary frequency response actions begin within

[2] An Interconnection is a geographic area in which the operation of the electric system is synchronized. In the continental United States, there are three Interconnections, namely the Eastern, Texas, and Western Interconnections.

[3] UFLS is designed for use in extreme conditions to stabilize the balance between generation and load. Under frequency protection schemes are drastic measures employed if system frequency falls below a specified value. *See Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,682, at PP 4-10 (2011) (Order No. 763 NOPR) at PP 4-10.

[4] In the Notice of Inquiry issued in Docket No. RM16-6-000 on Feb. 8, 2016, the Commission provided detailed discussion of how inertia, primary frequency response, and secondary frequency response interact to mitigate frequency deviations. *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, 154 FERC ¶ 61,117, at PP 3-7 (2016) (NOI). *See also Use of Frequency Response*

(continued ...)

seconds after system frequency changes and are mostly provided by the automatic and autonomous actions (i.e., outside of system operator control) of turbine-governors, while some response is provided by frequency responsive loads.[5] Primary frequency response actions are intended to arrest abnormal frequency deviations and ensure that system frequency remains within acceptable bounds. An important goal for system planners and operators is for the frequency nadir,[6] during large disturbances, to remain above the first stage of UFLS set points within an Interconnection.

7. Frequency response is a measure of an Interconnection's ability to arrest and stabilize frequency deviations following the sudden loss of generation or load, and is affected by the collective responses of generation and load throughout the Interconnection. When considered in aggregate, the primary frequency response

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Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation, Lawrence Berkeley National Laboratory, at 13-14 (Dec. 2010), http://energy.lbl.gov/ea/certs/pdf/lbnl-4142e.pdf (LBNL 2010 Report).

[5] NOI, 154 FERC ¶ 61,117 at P 6. The Commission also noted that regulation service is different than primary frequency response because generating facilities that provide regulation respond to automatic generation control signals and regulation service is centrally coordinated by the system operator, whereas primary frequency response service, in contrast, is autonomous and is not centrally coordinated. Schedule 3 of the *pro forma* Open Access Transmission Tariff (OATT) bundles these different services together, despite their differences. *See Id.* n.66.

[6] The point at which the frequency decline is arrested (following the sudden loss of generation) is called the frequency nadir, and represents the point at which the net primary frequency response (real power) output from all generating units and the decrease in power consumed by the load within an Interconnection matches the net initial loss of generation (in megawatts (MW)).

provided by generators within an Interconnection has a significant impact on the overall frequency response. NERC Reliability Standard BAL-003-1.1 defines the amount of frequency response needed from balancing authorities[7] to maintain Interconnection frequency within predefined bounds and includes requirements for the measurement and provision of frequency response.[8] While NERC Reliability Standard BAL-003-1.1 establishes requirements for balancing authorities, it does not include any requirements for individual generator owners or operators.[9]

8. Unless otherwise required by tariffs or interconnection agreements, generator owners and operators can independently decide whether units are configured to provide primary frequency response.[10] The magnitude and duration of a generator's response to

[7] NERC's Glossary of Terms defines a balancing authority as "(t)he 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."

[8] *Frequency Response and Frequency Bias Setting Reliability Standard*, Order No. 794, 146 FERC ¶ 61,024 (2014).

[9] The Commission has also accepted Regional Reliability Standard BAL-001-TRE-01 (Primary Frequency Response in the ERCOT Region) as mandatory and enforceable, which does establish requirements for generator owners and operators with respect to governor control settings and the provision of primary frequency response within the Electric Reliability Council of Texas (ERCOT) region. *North American Electric Reliability Corporation*, 146 FERC ¶ 61,025 (2014).

[10] *See* NOI, 154 FERC ¶ 61,117 at PP 18-19.

frequency deviations is generally determined by the settings of the unit's governor[11] (or equivalent controls) and other plant level (e.g., "outer-loop") control systems. In particular, the governor's droop and deadband settings have a significant impact on the unit's provision of primary frequency response. In addition, plant-level or "outer-loop" controls, unless properly configured, can override or nullify a generator's governor response and return the unit to operate at a scheduled pre-disturbance megawatt set-point.[12] In 2010, NERC conducted a survey of generator owners and operators and found that only approximately 30 percent of generators in the Eastern Interconnection provided primary frequency response, and that only approximately 10 percent of generators provided sustained primary frequency response.[13] This suggests that many generators

[11] A governor is an electronic or mechanical device that implements primary frequency response on a generator via a droop parameter. Droop refers to the variation in real power (MW) output due to variations in system frequency and is typically expressed as a percentage (e.g., 5 percent droop). Droop reflects the amount of frequency change from nominal (e.g., 5 percent of 60 Hz is 3 Hz) that is necessary to cause the main prime mover control mechanism of a generating facility to move from fully closed to fully open. A governor also has a deadband parameter which establishes a minimum frequency deviation (e.g., ±0.036 Hz) from nominal that must be exceeded in order for the governor to act.

[12] For more discussion on "premature withdrawal" of primary frequency response, *see* NOI, 154 FERC ¶ 61,117 at PP 49-50.

[13] *See* NERC *Frequency Response Initiative Report: The Reliability Role of Frequency Response* (Oct. 2012), http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf (NERC Frequency Response Initiative Report) at 95.

within the Interconnection disable or otherwise set their governors or outer-loop controls such that they provide little to no primary frequency response.[14]

9. Declining frequency response performance has been an industry concern for many years. NERC, in conjunction with EPRI, initiated its first examination of declining frequency response and governor response in 1991.[15] More recently, as noted in the NOI, while the three U.S. Interconnections currently exhibit adequate frequency response performance above their Interconnection Frequency Response Obligations,[16] there has been a significant decline in the frequency response performance of the Western and Eastern Interconnections.[17]

[14] However, as noted below, some commenters note that nuclear generating units are restricted by their U.S. Nuclear Regulatory Commission operating licenses regarding the provision of primary frequency response.

[15] NERC Frequency Response Initiative Report at 22.

[16] The Interconnection Frequency Response Obligations are established by NERC and are designed to require sufficient frequency response for each Interconnection (i.e., the Eastern, ERCOT, Quebec and Western Interconnections) to arrest frequency declines even for severe, but possible, contingencies.

[17] NOI, 154 FERC ¶ 61,117 at P 20.

B. Prior Commission Actions

10. In Order Nos. 2003[18] and 2006,[19] the Commission adopted standard procedures for the interconnection of large and small generating facilities, including the development of standardized *pro forma* generator interconnection agreements and procedures. The Commission required public utility transmission providers[20] to file revised OATTs containing these standardized provisions, and use the LGIA and SGIA to provide non-discriminatory interconnection service to Large Generators (i.e., generating facilities having a capacity of more than 20 MW) and Small Generators (i.e., generators having a

[18] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

[19] *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, FERC Stats. & Regs. ¶ 31,180, *order on reh'g*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005), *order granting clarification*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006).

[20] A public utility is a utility that owns, controls, or operates facilities used for transmitting electric energy in interstate commerce, as defined by the FPA. *See* 16 U.S.C. § 824(e) (2012). A non-public utility that seeks voluntary compliance with the reciprocity condition of an OATT may satisfy that condition by filing an OATT, which includes a LGIA and SGIA. *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at PP 840-845.

capacity of no more than 20 MW). The *pro forma* LGIA and *pro forma* SGIA have since been revised through various subsequent proceedings.[21]

11. As relevant here, the *pro forma* LGIA and *pro forma* SGIA are largely silent on any requirements with respect to primary frequency response. In particular, the only requirement in the *pro forma* LGIA or *pro forma* SGIA related to primary frequency response is contained within current Article 9.6.2.1 of the *pro forma* LGIA (Governors and Regulators), which provides that *if* speed governors are installed, they should be operated in automatic mode.[22] A speed governor implements the primary frequency response provided by a synchronous generating facility; however, Article 9.6.2.1 does not address governor settings or plant-level controls, which also affect the ability of a generating facility to provide primary frequency response. In addition, Article 9.6.2.1 does not require the installation of the necessary equipment for frequency response capability (i.e., governors or equivalent controls). Finally, the *pro forma* SGIA does not contain any provisions related to primary frequency response.

[21] *E.g.*, *Small Generator Interconnection Agreements and Procedures*, Order No. 792, 145 FERC ¶ 61,159 (2013), *clarifying*, Order No. 792-A, 146 FERC ¶ 61,214 (2014); *Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 81 Fed. Reg. 40,793 (Jun. 23, 2016), 155 FERC ¶ 61,277 (2016); *Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities*, Order No. 828, 81 Fed. Reg. 50,290 (Aug. 1, 2016), 156 FERC ¶ 61,062 (2016).

[22] Article 9.6.2.1 of the *pro forma* LGIA.

C. Efforts to Evaluate the Impacts of the Changing Resource Mix

12. The Commission's *pro forma* generator interconnection agreements and procedures were developed at a time when traditional synchronous generating facilities with standard governor controls and large rotational inertia were the predominant sources of electricity generation. However, the nation's resource mix has undergone significant change since the issuance of Order Nos. 2003 and 2006. This transformation has been characterized by the retirement of baseload, synchronous generating facilities and the integration of more distributed generation, demand response, and natural gas generating facilities, and the rapid expansion of non-synchronous variable energy resources (VERs) such as wind and solar.[23] For example, the U.S. Energy Information Administration (EIA) has observed that the U.S. added approximately 13 gigawatts (GW) of wind, 6.2 GW of utility scale solar photovoltaic (PV), and 3.6 GW of distributed solar PV generating facilities in 2014 and 2015.[24] Conversely, NERC has reported[25] that almost 42 GW of synchronous generating facilities (e.g., coal, nuclear, and natural gas) have

[23] The term VER is defined as a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. *See, e.g.*, *Integration of Variable Energy Resources*, Order No. 764, FERC Stats. & Regs. ¶ 31,331, at P 210 (2012).

[24] *See, U.S. electric generation capacity additions, 2015 vs. 2014*, EIA (March 2016), https://www.eia.gov/todayinenergy/detail.php?id=25492.

[25] *See* NERC 2015 LTRA (Dec. 2015), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2015LTRA%20-%20Final%20Report.pdf.

retired between 2011 and 2014, and the EIA recently reported that nearly 14 GW of coal and 3 GW of natural gas generating facilities retired in 2015.[26]

13. While technological advancements have enabled wind and solar generating facilities to now have the ability to provide primary frequency response, this functionality has not historically been a standard feature that was included and enabled on non-synchronous generating facilities. Moreover, wind and solar generating facilities typically operate at their maximum operating output, leaving no capacity (or "headroom") [27] to provide primary frequency response during under-frequency conditions.

14. Given the changes in the resource mix and concerns about the significant decline in frequency response for the Eastern and Western Interconnections,[28] NERC has undertaken several initiatives to evaluate the impacts of the changing resource mix, particularly with respect to primary frequency response. For example, in 2014, NERC initiated the Essential Reliability Services Task Force (Task Force) to analyze and better

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[26] *See Electricity generating capacity retired in 2015 by fuel and technology*, EIA (May 2016), http://www.eia.gov/todayinenergy/detail.php?id=25272.

[27] Headroom refers to the difference between the current operating point of a generator and its maximum operating capability, and represents the potential amount of additional energy that can be provided by the generating facility in real-time.

[28] *See* NERC *Frequency Response Initiative Industry Advisory – Generator Governor Frequency Response*, at slide 10 (Apr. 2015), http://www.nerc.com/pa/rrm/Webinars%20DL/Generator_Governor_Frequency_Response_Webinar_April_2015.pdf. (NERC 2015 Frequency Response Webinar). *See* also LBNL 2010 Report at pp xiv-xv.

understand the impacts of the changing resource mix and develop technical assessments of essential reliability services.[29] The Task Force focused on three essential reliability services: frequency support, ramping capability, and voltage support.[30] The Task Force considered the seven ancillary services[31] adopted by the Commission in Order Nos. 888[32]

[29] Essential reliability services are referred to as elemental reliability building blocks from resources (generation and load) that are necessary to maintain the reliability of the Bulk-Power System. *See* Essential Reliability Services Task Force Scope Document, at 1 (Apr. 2014), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Scope_ERSTF_Final.pdf.

[30] Essential Reliability Services Task Force Measures Report, at 22 (Dec. 2015), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.

[31] The seven *pro forma* ancillary services set forth in Order Nos. 888 and 890 are: (1) Scheduling, System Control and Dispatch Service; (2) Reactive Supply and Voltage Control from Generation Sources Service; (3) Regulation and Frequency Response Service; (4) Energy Imbalance Service; (5) Operating Reserve - Spinning Reserve Service; (6) Operating Reserve - Supplemental Reserve Service; and (7) Generator Imbalance Service.

[32] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

and 890[33] as a subset of the essential reliability services that may need to be augmented by additional services as the Bulk-Power System[34] characteristics change.

15. The Task Force did not recommend new reliability standards or specific actions to alter the existing suite of ancillary services; however, it did make certain conclusions with regard to primary frequency response. Specifically, the Task Force concluded that it is prudent and necessary to ensure that primary frequency response capabilities are present in the future generation resource mix, and recommended that all new generators support the capability to manage frequency.[35]

16. In addition, as part of its ongoing analysis of primary frequency response concerns, NERC observed in a 2012 report that a number of generators implemented deadband settings that were so wide as to effectively defeat the ability to provide primary

[33] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[34] Section 215(a)(1) of the Federal Power Act (FPA), 16 U.S.C. § 824o(a)(1) (2012) defines "Bulk-Power System" as those "facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) [and] electric energy from generating facilities needed to maintain transmission system reliability." The term does not include facilities used in the local distribution of electric energy. *See also Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 76, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[35] Essential Reliability Services Task Force Measures Report at vi.

frequency response.[36] The report also notes that many generators provide frequency response in the wrong direction during a disturbance.[37] Additionally, in February 2015, NERC issued an Industry Advisory that determined that a significant portion of generators within the Eastern Interconnection use deadbands or governor control settings that either inhibit or prevent the provision of primary frequency response.[38] Moreover, as noted in the NOI, NERC observed in 2015 that in many conventional steam plants, deadband settings exceed ±0.036 Hz, resulting in primary frequency response that is not sustained, and that the vast majority of the gas turbine fleet is not frequency responsive.[39] In response to these issues and other concerns, NERC's Operating Committee approved a voluntary Primary Frequency Control Guideline that contains recommended settings for generator governors and other plant control systems, and encourages generators within the three U.S. Interconnections to provide sustained and effective primary frequency

[36] NERC Frequency Response Initiative Report at 92.

[37] NERC Frequency Response Initiative Report at 96-97.

[38] NERC Generator Governor Frequency Response Industry Advisory (Feb. 2015), http://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/2015%20Alerts/NERC%20Alert%20A-2015-02-05-01%20Generator%20Governor%20Frequency%20Response.pdf.

[39] NOI, 154 FERC ¶ 61,117 at P 50 (citing to NERC 2015 Frequency Response Webinar at 1).

response.[40] NERC's Guideline recommends maximum 5 percent droop and ±0.036 Hz deadband settings for most generating facilities.[41]

D. Initiatives by Individual Transmission Providers

17. While the *pro forma* LGIA and *pro forma* SGIA do not provide specific requirements related to frequency response, some public utility transmission providers have included provisions related to primary frequency response in their LGIA, SGIA, OATTs, and/or business practice manuals.

18. For example, ISO New England Inc. (ISO-NE) and New York Independent System Operator, Inc. (NYISO) have adopted provisions to their LGIAs that establish more specific requirements for governor operation.[42] In particular, ISO-NE requires each generator within its region with a capability of 10 MW or more, including VERs, to operate with a functioning governor with specified droop and deadband settings, i.e., maximum 5 percent droop and ±0.036 Hz deadband, and to also ensure that the

[40] *See* NERC Primary Frequency Control Guideline Final Draft (Dec. 2015), http://www.nerc.com/comm/OC/Reliability%20Guideline%20DL/Primary_Frequency_Control_final.pdf (NERC Primary Frequency Control Guideline). *See also* NERC Operating Committee Meeting Minutes (Jan. 2016), http://www.nerc.com/comm/OC/AgendasHighlightsMinutes/Operating%20Committee%20Minutes%20-%20Dec%2015-16%202015-Final.pdf.

[41] *See* NERC Primary Frequency Control Guideline at 7-9.

[42] *See* ISO-NE, Transmission, Markets and Services Tariff, Schedule 22 Large Generator Interconnection Procedures (9.0.0), Appendix 6, § 9.6.2.2; NYISO, NYISO Tariffs, NYISO OATT, 30.14 OATT Att. X Appendices (8.0.0), Appendix 6, § 9.5.4.

provision of primary frequency response is not inhibited by the effects of outer-loop controls.[43]

19. PJM Interconnection, L.L.C. (PJM) has implemented governor droop and deadband requirements, i.e., maximum 5 percent droop and ±0.036 Hz deadband, for all generating facilities excluding nuclear facilities with a gross plant/facility aggregate nameplate rating greater than 75 MVA.[44] PJM also recently added new interconnection requirements requiring new non-synchronous generators to interconnect with "enhanced inverters" that have various capabilities including, among other things, the ability to provide primary frequency response.[45]

20. Midcontinent Independent System Operator, Inc. (MISO) requires governor operation as a condition for providing regulating reserve but does not require specific settings.[46] Also, the Commission recently accepted tariff provisions proposed by the

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[43] *See* ISO-NE's Operating Procedure No. 14 § I (Governor Control), http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14_rto_final.pdf.

[44] PJM's *pro forma* interconnection agreements obligate interconnection customers within its region to abide by all PJM rules and procedures, including rules set forth in PJM's Manuals (*See* PJM Tariff, Attachment O § 8.0). *See also* PJM Manual 14D § 7.1.1 (Generator Real-Power Control), http://www.pjm.com/~/media/documents/manuals/m14d.ashx.

[45] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,097, at n.58 (2015).

[46] *See* MISO, FERC Electric Tariff, Module C, Energy and Operating Reserve Markets § 39.2.1B (34.0.0) ("All Regulation Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must be capable of automatically responding to and alleviating frequency deviations through a speed governor or similar device in accordance with the Applicable Reliability Standards.").

California Independent System Operator Corporation (CAISO) to require governor operation, specified droop and deadband settings, i.e., maximum 5 percent droop and ±0.036 Hz deadband, and provisions for sustained primary frequency response for its participating generators that have traditional governor controls.[47]

E. Notice of Inquiry

1. Summary

21. On February 18, 2016, the Commission issued the NOI to explore issues regarding essential reliability services and the evolving Bulk-Power System.[48] In particular, the Commission asked a broad range of questions on the need for reform of its rules and regulations regarding the provision of and compensation for primary frequency response. The Commission explained that there is a significant risk that, as conventional synchronous generating facilities retire or are displaced by increased numbers of VERs that do not typically contribute to system inertia or have primary frequency response capabilities, the net amount of frequency responsive generation online will be reduced.[49] The Commission also explained that these developments and their potential impacts could challenge system operators in maintaining reliability.[50] Further, the Commission explained that NERC Reliability Standard BAL-003-1.1 and the *pro forma* LGIA and *pro*

[47] *CAISO*, 156 FERC ¶ 61,182, at PP 10-12 and 17 (2016).

[48] NOI, 154 FERC ¶ 61,117.

[49] *Id.* P 12.

[50] *Id.* P 14.

forma SGIA do not specifically address a generator's ability to provide frequency response.[51] The Commission noted, however, that while in previous years many non-synchronous generating facilities were not designed with primary frequency response capabilities, the technology now exists for new non-synchronous generating facilities to install primary frequency response capability.[52]

22. Accordingly, the Commission requested comments on three main sets of issues. First, the Commission sought comment on whether amendments to the *pro forma* LGIA and *pro forma* SGIA are warranted to require all new generating facilities, both synchronous and non-synchronous, to have primary frequency response capabilities as a precondition of interconnection.[53] Second, the Commission sought comment on the performance of existing generating facilities and whether primary frequency response requirements for these facilities are warranted.[54] Finally, the Commission sought comment on compensation for primary frequency response.[55]

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[51] *Id.* P 41.

[52] *Id.* P 43.

[53] *Id.* PP 2 and 44-45.

[54] *Id.* PP 2, 46, and 52.

[55] *Id.* PP 2, 53-54.

2. Comments on modifying the *pro forma* LGIA and *pro forma* SGIA

23. The Commission received a robust response from industry, with 47 entities collectively submitting nearly 700 pages of comments that provided responses to some or all of the questions posed by the NOI.[56] Relevant to the proposed revisions considered in this NOPR, the Commission received numerous comments on whether the *pro forma* LGIA and *pro forma* SGIA should be revised to include requirements for all newly interconnecting generating facilities, whether synchronous or non-synchronous, to install primary frequency response capability.[57]

a. Comments in support of modifying the *pro forma* LGIA and *pro forma* SGIA

24. Most commenters support, or are not opposed to, revising the *pro forma* LGIA and SGIA to impose primary frequency response capability requirements on all new generating facilities as suggested in the NOI.[58] Several commenters indicate that the

[56] The Appendix lists the entities that submitted comments and the shortened names that are used throughout this NOPR.

[57] NOI, 154 FERC ¶ 61,117 at P 45.

[58] APPA, *et al.* Comments at 6; Bonneville Comments at 6; CAISO Comments at 2; California Cities Comments at 2; ELCON Comments at 5; EEI Comments at 12; EPSA, *et al.* Comments at 8; Howard F. Illian Comments at 43; Idaho Power Comments at 1; IEEE-PES Comments at 1; Indicated ISOs/RTOs Comments at 3; ITC, *et al.* Comments at 1; MISO Comments at 4; MISO TOs Comments at 6; NARUC Comments at 3; NERC Comments at 17; North American Generator Forum Comments at 2; Peak Reliability Comments at 4; PG&E Comments at 2; SoCal Edison Comments at 4; Southern Company Comments at 2; Tri-State Generation Comments at 3; WIRAB Comments at 3.

(continued ...)

nation's changing resource mix could create reliability concerns related to the provision of primary frequency response. For example, PJM Utilities Coalition states that while newer generating facilities are not installing frequency response capability, the existing generating facilities that do provide this essential reliability service have more limited capability, due to the cost of operation and planned retirements, placing the grid at further risk.[59] Peak Reliability, the reliability coordinator for the Western Interconnection, states that as baseload generation retires, the number of generators providing primary frequency response is reduced and may present reliability challenges for system operators, as fewer options are available to reduce frequency deviations following an unexpected loss of generation or load.[60] CAISO asserts that due to the increased proportion of renewable generating facilities operating in CAISO's balancing authority area, there may not be sufficient frequency responsive capacity online when the system has high renewable output and low load levels.[61] Bonneville states that the trend of declining frequency response capability will continue with a changing resource mix, unless provisions are put in place to assure that adequate inertial and primary frequency response capability are

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[59] PJM Utilities Coalition Comments at 3.

[60] Peak Reliability Comments at 4.

[61] CAISO Comments at 2.

available in the future.[62] NERC states that the rapidly changing resource mix may reduce the level of available frequency capability.[63]

25. Numerous commenters assert that they recognize the benefits of revising the *pro forma* LGIA and *pro forma* SGIA to require primary frequency response capabilities for new generators. NERC, for example, asserts that new primary frequency response requirements for generators will improve operator flexibility for system restoration and island capability and help balancing authorities meet their frequency response obligations.[64] NERC also asserts that revisions to the *pro forma* LGIA and *pro forma* SGIA would result in measurable, clear requirements applicable to all new generating facilities in a fair and equitable manner.[65] NERC points out, however, that primary frequency response capability, by itself, would not require a resource to respond if called upon to help a balancing authority meet its frequency response obligation, and that, as a result, it is important to have mechanisms to ensure that sufficient frequency response capability is not only available but ready to respond at all times.[66] CASIO, Indicated ISOs/RTOs, MISO, and a number of trade associations also support modifications to the

[62] Bonneville Comments at 2.

[63] NERC Comments at 17.

[64] *Id.*

[65] *Id.*

[66] *Id.* at 18.

pro forma LGIA and *pro forma* SGIA for new generating facilities to install primary frequency response capability.[67] PJM Utilities Coalition states that, with all new generating facilities (both synchronous and non-synchronous) being fully capable of providing primary frequency response, requiring this capability will ensure that system operators have the ability to reliably operate the grid of the future.[68] Peak Reliability states that it supports modifications to the *pro forma* LGIA and *pro forma* SGIA and that requiring generating facilities to install or provide frequency response in the initial stages of the interconnection process will ensure that the grid is able to maintain this essential service even as the resource mix changes.[69]

26. Other commenters also express support for revising the *pro forma* LGIA and *pro forma* SGIA. Bonneville points out that selling primary frequency response capability would not provide sufficient incentive for new generating facilities to invest in such capability, and argues that the only way to ensure that there is enough primary frequency response capability is to require new generators to install it.[70] WIRAB advises that while current studies do not indicate that there is a shortage of primary frequency

[67] APPA, *et al.* Comments at 2; CAISO Comments at 2; EEI Comments at 3; EPSA, *et al.* Comments at 8; Indicated ISOs/RTOs Comments at 3; MISO Comments at 4; North American Generator Forum Comments at 2.

[68] PJM Utilities Coalition Comments at 4-5.

[69] Peak Reliability Comments at 4-5.

[70] Bonneville Comments at 21.

response in the Western Interconnection and that all generators do not need to provide primary frequency response all of the time, the Commission should, however, require that all new generator owners install primary frequency response capability because of the changing resource mix in the Western Interconnection and the associated uncertainty regarding the future provision of primary frequency response.[71]

27. Several commenters that generally support revising the *pro forma* LGIA and *pro forma* SGIA also express certain concerns. For example, Southern Company expresses support for revising the *pro forma* LGIA and *pro forma* SGIA, but caveats its support by arguing that new regulations for primary frequency response should include an "opt-out" provision that would allow balancing authorities that do not anticipate frequency response shortfalls to delay the implementation of the new *pro forma* LGIA and *pro forma* SGIA requirements until these needs are actually anticipated in their regions in order to avoid higher costs.[72] EPSA, *et al.* state that while they do not fully oppose amending the *pro forma* LGIA and *pro forma* SGIA, they recommend that the Commission explore more effective and cost efficient ways to address the range of issues posed in the NOI and consider a measured approach before mandating governors for all prospective interconnecting generation.[73]

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[71] WIRAB Comments at 5-6.

[72] Southern Company Comments at 2-3.

[73] EPSA, *et al.* Comments at 8-9.

28. Some commenters that support modifying the *pro forma* LGIA and *pro forma* SGIA also assert that the costs of implementing primary frequency response capability for new generating facilities are low.[74] For example, APPA, *et al.* state that the capability for providing primary frequency response is almost always installed in synchronous generation, and that the inclusion of this additional control for new non-synchronous generating facilities would likely add only nominal costs.[75] EEI asserts that all new generating facilities coming online can be fully capable of providing primary frequency response and that the associated cost of installing such capability during initial manufacturing or construction of a new VER is small when considering the overall cost of the new generating facility.[76]

29. In contrast to new generating facilities, some entities, however, explain that the costs of retrofitting existing generating facilities with primary frequency response capability could be significant in some cases.[77] For example, WIRAB states that the high

[74] APPA, *et al.* Comments at 6; Bonneville Comments at 8; California Cities Comments at 2; EEI Comments at 13; Indicated ISOs/RTOs Comments at 5; MISO Comments at 4; SoCal Edison Comments at 2.

[75] APPA, *et al.* Comments at 6.

[76] EEI Comments at 13.

[77] APPA, *et al.* Comments at 6; Bonneville Comments at 8; California Cities Comments at 8; EEI Comments at 14; Idaho Power Comments at 4; WIRAB Comments at 6.

cost of retrofitting existing generators to install the necessary control equipment supports limiting the requirement to new generators and taking early action now.[78]

30. In regards to nuclear generating facilities, some commenters indicate that nuclear plants have separate licensing requirements under the Nuclear Regulatory Commission and should not be required to provide primary frequency response. For example, the Nuclear Energy Institute asserts that while nearly all new generating facilities should be able to provide primary frequency response, nuclear plants are not well-suited to provide primary frequency response due to restrictions by their operating licenses issued by the Nuclear Regulatory Commission.[79] The Nuclear Energy Institute also asserts that turbine controls on most nuclear units are designed to maintain the internal steam pressure and are not intended to react to changes in the grid.[80] Similarly, the MISO TOs assert that requiring nuclear units to have primary frequency response capability would be contrary to Nuclear Regulatory Commission licensing requirements, and could have a detrimental effect on the safety of the nuclear fleet.[81]

31. In the NOI, the Commission also sought comment on whether it would be appropriate to include recommended governor settings contained within NERC's Primary

[78] WIRAB Comments at 6.

[79] Nuclear Energy Institute Comments at 1 and 4.

[80] Nuclear Energy Institute Comments at 4.

[81] MISO TOs Comments at 7.

Frequency Control Guideline in the *pro forma* LGIA and *pro forma* SGIA.[82] Numerous commenters express support for including NERC's recommended governor control settings in the *pro forma* LGIA and *pro forma* SGIA.[83] Some commenters note that NERC's Guideline is consistent with existing regulations or practices in certain regions.[84] Indicated ISOs/RTOs point out that common primary frequency response settings for generators in an Interconnection will enhance reliability by reducing maneuvering by individual generators.[85] MISO asserts that NERC's Guideline provides a sound baseline.[86] NERC notes that its Guideline was developed by technical committees with expertise and judgment of the electric industry, and accordingly, the Guideline is the "most advanced set of nation-wide best practices and information currently available to support frequency response capability."[87]

32. However, not all entities that support modifying the *pro forma* LGIA and *pro forma* SGIA endorse the inclusion of NERC's recommended governor settings. For example, EEI states that it does not support including prescriptive performance

[82] NOI, 154 FERC ¶ 61,117 at P 45.

[83] *See e.g.,* Bonneville Comments at 7; IEEE-PES Comments at 1; Indicated ISOs/RTOs Comments at 4; California Cities Comments at 2; WIRAB Comments at 7.

[84] Indicated ISOs/RTOs Comments at 4; SoCal Edison Comments at 4; Peak Reliability Comments at 7; Manitoba Comments at 8.

[85] Indicated ISOs/RTOs Comments at 5.

[86] MISO Comments at 4.

[87] NERC Comments at 12.

requirements for governor control settings or other performance indicators in the *pro forma* LGIA or *pro forma* SGIA due to the physical, technical, or operational limitations of new generating facilities to provide primary frequency response.[88] Similarly, APPA, *et al.* state that they do not support revising the *pro forma* LGIA and *pro forma* SGIA to include the recommended settings contained within NERC's Guideline at this time.[89] MISO TOs state that some transmission owners in MISO believe that NERC's recommended governor settings are appropriate for traditional synchronous generating facilities, but recommend additional consideration for other generation technologies.[90] On the other hand, MISO TOs state that other transmission owners in MISO request flexibility and assert that specified governor settings should not be "hard-wired" or dictated in the *pro forma* LGIA and *pro forma* SGIA.[91]

b. Comments opposed to modifying the *pro forma* LGIA and *pro forma* SGIA

33. Other commenters contend that the *pro forma* LGIA and *pro forma* SGIA should not be modified to require primary frequency response capability from new generating

[88] EEI Comments at 15-17.

[89] APPA, et al. Comments at 8.

[90] MISO TOs Comments at 8.

[91] MISO TOs Comments at 8.

facilities.[92] Some commenters argue that requiring all new generating facilities to have primary frequency response capability will result in extra costs above those necessary to ensure reliability.[93] For example, APS argues that a global mandate to provide primary frequency response or to require generating facilities to be primary frequency response capable would result in significantly increased costs while providing a disproportionately minor impact on improving reliability.[94] Powerex asserts that modifying the *pro forma* LGIA and *pro forma* SGIA to include minimum primary frequency response requirements will increase the cost of entry for new generators, particularly VERs, which typically are not designed with such capability.[95] Several commenters note that there would be a significant opportunity cost for certain generating facilities to reserve headroom for the provision of primary frequency response.[96]

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[92] AES Companies Comments at 6; Apex Comments at 6; APS Comments at 6; AWEA Comments at 12; Chelan County Comments at 2; ESA Comments at 2; Grid Storage Consulting Comments at 2; Microgrids Resources Coalition Comments at 3; NRECA Comments at 9; Powerex Comments at 5; SDG&E Comments at 3; SolarCity Comments at 1; TVA Comments at 2.

[93] Apex Comments at 5-6; APS Comments at 6; AWEA Comments at 12; Chelan County Comments at 2; Powerex Comments at 5; Solar City Comments at 1.

[94] APS Comments at 6. It is unclear whether the increased costs referenced by APS refer only to the costs for the necessary equipment to provide primary frequency response or the costs associated with maintaining the headroom necessary to provide primary frequency response.

[95] Powerex Comments at 5.

[96] Apex Comments at 7; Solar City Comments at 1; AWEA Comments at 6.

34. Some of the commenters that are opposed to modifying the *pro forma* LGIA and pro *forma* SGIA assert that they prefer a market-based approach instead of a requirement for new generating facilities to install primary frequency response capability.[97] For example, AWEA asserts that, initially, the *pro forma* LGIA and *pro forma* SGIA should not be revised to require new generating facilities to have primary frequency response capability, and only if market-based steps do not satisfactorily address the need for primary frequency response, then the Commission could consider an additional requirement for new generating facilities to have such capability as a final step.[98]

35. Other commenters oppose mandatory requirements and prefer a voluntary approach to improving primary frequency response performance.[99] For example, TVA asserts that if current voluntary actions fail to show improvement in primary frequency response, then the *pro forma* LGIA and *pro forma* SGIA could be revised to contain a general primary frequency response requirement, similar to reactive power, but that NERC should be directed to establish governor settings and performance requirements through the NERC Standards Development Process instead of the Commission including such requirements in the *pro forma* LGIA and *pro forma* SGIA.[100] Some commenters

[97] Apex Comments at 6; AWEA Comments at 12; Chelan County Comments at 2; ESA Comments at 2; SDG&E Comments at 3.

[98] AWEA Comments at 12.

[99] APS Comments at 8; NRECA Comments at 6; TVA Comments at 2.

[100] TVA Comments at 2-3 and 5.

assert that governor control details are better left to individual balancing authorities.[101] For example, APS argues that the Commission should allow balancing authorities to determine the type and magnitude of generating facilities within its balancing authority area that are frequency-response enabled.[102] APS also points out that any need to install frequency response capability or otherwise support frequency response performance can and should be evaluated and agreed upon between a generating facility and the transmission provider during the interconnection study process.[103]

II. Discussion

A. Primary Frequency Response Requirements

1. The Need for Reform

36. Pursuant to FPA section 206, the Commission preliminarily finds that conditions have changed since the issuance of Order Nos. 2003 and 2006 and certain aspects of the *pro forma* LGIA and *pro forma* SGIA may now be unjust, unreasonable, unduly discriminatory, or preferential.[104] Specifically, as discussed above, the record indicates that while the frequency response performance of the Eastern and Western Interconnections is currently adequate, the frequency response performance of both

[101] APS Comments at 8; AES Companies Comments at 8.

[102] APS Comments at 8.

[103] *Id.* at 15.

[104] The Commission routinely evaluates the effectiveness of its regulations and policies in light of changing industry conditions to determine if changes are necessary. *See, e.g.*, Order No. 764, FERC Stats. & Regs. ¶ 31,331.

Interconnections has significantly declined from historic values.[105] Furthermore, the record shows that there is an ongoing evolution of the nation's generation resource mix, including significant retirements of baseload generation and an increasing proportion of VERs interconnecting to the electric grid.[106] Several commenters point out that there is significant risk that the rapidly changing resource mix may reduce the level of available frequency response capability online.[107] This is in part because, as noted in the NOI, VERs have not been consistently designed with primary frequency response capabilities.[108] The record suggests, however, that VER manufacturers have made significant technological advancements in recent years to develop primary frequency response capability for VERs.[109] In addition, NERC, in conjunction with various industry stakeholders, has developed more robust technical guidance for the operation of governors or equivalent controls.[110] As a result of the evolving resource mix and the potential for adverse impacts on primary frequency response, the Commission is concerned that there may be potential reliability impacts if it does not undertake the reforms proposed in this NOPR. Moreover, the Commission is concerned that certain aspects of the existing *pro forma* LGIA and *pro forma* SGIA may no longer be just and reasonable.

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[105] *See* NERC 2015 Frequency Response Webinar at 10, NERC Frequency Response Initiative Report at 22, and LBNL 2010 Report at pp xiv-xv.

[106] *See, e.g.*, P 12, *supra* (describing recent and ongoing changes in the nation's generation mix).

[107] *See, e.g.*, Bonneville Comments at 2; CAISO Comments at 2; NERC Comments at 17; Peak Reliability Comments at 4; PJM Utilities Coalition Comments at 3.

[108] NOI, 154 FERC ¶ 61,117 at PP 42-43.

[109] *See, e.g.*, PJM Utilities Comments at 4-5; EEI Comments at 13. *See also* PJM Interconnection, L.L.C., Docket No. ER15-1193-000 (March 6, 2015) Transmittal Letter at 11. *See also* NERC 2014 LTRA, at 27 (Nov. 2014), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA_ERATTA.pdf.

[110] *See* P 16, *supra*.

37. First, the current requirements for governor controls in the *pro forma* LGIA do not reflect advances in technology or the latest recommended operating practices. Specifically, current Article 9.6.2.1 states that "speed governors," if installed, must be operated in automatic mode. However, many of the new generating facilities interconnecting to the grid, such as wind and solar, do not utilize traditional speed governors; instead they utilize enhanced inverters and other plant supervisory control technology that can be designed to include primary frequency response capability.[111] Therefore, due to advancements in technology, the Commission preliminarily finds that the existing references to "speed governors" in Article 9.6.2.1 that apply only to synchronous resources are outdated, and therefore may no longer be just and reasonable.

38. Second, since the issuance of Order No. 2003 and the establishment of the *pro forma* LGIA, NERC, in conjunction with industry stakeholders, has amassed a significant body of knowledge in regards to the operation of generator governors and plant control systems. For example, as noted above, NERC observed in 2012 that a number of generators implemented deadband settings that were so wide as to effectively defeat the ability to provide primary frequency response, and that many generators

[111] *See* Electric Power Research Institute, *Recommended Settings for Voltage and Frequency Ride Through of Distributed Energy Resources* (May 2015) at 27, http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002006203. *See also* National Renewable Energy Labs (NREL), *Advanced Grid-Friendly Controls Demonstration Project for Utility-Scale PV Power Plants*, at 1-2 (Jan. 2016), http://www.nrel.gov/docs/fy16osti/65368.pdf.

provide frequency response in the wrong direction during a disturbance.[112] Additionally, as noted above, NERC observed in 2015 that in many conventional steam plants, deadband settings exceed a ±0.036 Hz dead band, resulting in primary frequency response that is not sustained, and that the vast majority of the gas turbine fleet is not frequency responsive.[113]

39. The record here suggests that the actual governor and plant control system settings that are being implemented by some generator owners and/or operators may be defeating the intent of Article 9.6.2.1 of the *pro forma* LGIA. In response to these issues, NERC, through the work of its various task forces, subcommittees, and initiatives, has developed a voluntary Guideline that includes recommended droop and deadband settings based on significant investigation.[114] However, the *pro forma* LGIA does not currently reflect these updated recommended practices for governor and plant control system settings of generating facilities.

40. Third, given the nation's evolving resource mix and the potential adverse impacts on primary frequency response as noted in the NOI and pointed out by several commenters, the Commission believes that changes to the *pro forma* LGIA and *pro forma* SGIA may be necessary to provide for the continued reliable operation of the

[112] *See* P 16, *supra*.

[113] *Id.*

[114] *See* NERC Primary Frequency Control Guideline.

power system. As noted above, the Task Force concluded that all new generating facilities should be required to be capable of providing primary frequency response.[115] However, the *pro forma* LGIA does not currently require large generating facilities to install such capability; rather, it only requires governor operation in "automatic mode" *if* a "speed governor" is installed.[116]

41. In addition, the Commission is concerned that the current *pro forma* SGIA may be unduly discriminatory or preferential because it does not establish any specific requirements with respect to the installation or operation of governors or equivalent frequency control equipment. In particular, the *pro forma* SGIA does not have a similar provision to Article 9.6.2.1 of the *pro forma* LGIA. The Commission has previously acted under FPA section 206 to remove inconsistencies between the *pro forma* LGIA and *pro forma* SGIA when there is no economic or technical basis for treating large and small generating facilities differently.[117] Similarly, in this instance, the record developed from the NOI appears to suggest that small generating facilities are capable of installing and

[115] *See* P 15, *supra*.

[116] Article 9.6.2.1 of the *pro forma* LGIA.

[117] *See Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities*, Order No. 828, 81 FR 50,290 (Aug. 1, 2016), 156 FERC ¶ 61,062 (2016), (The Final Rule revised the *pro forma* SGIA such that small generating facilities have frequency and voltage ride through requirements comparable to large generating facilities).

enabling governors at low cost in a manner comparable to large generating facilities.[118] As discussed above, the record indicates that there have been significant advances in technology, as well as the development of more robust technical guidance for the operation of governors or equivalent controls for both large and small generating facilities.[119] In particular, the IEEE-P1547 Working Group noted that its new IEEE-1547 standard for interconnecting distributed generation will likely include certain requirements for providing primary frequency response.[120] Given these low-cost technological advances, the Commission does not anticipate that these additional requirements added in the *pro forma* SGIA will present a barrier to entry for small generating facilities. And, given the need for additional primary frequency response capability and an increasingly large market penetration of small generating facilities, the Commission believes that there is a need to add these requirements to the *pro forma* SGIA to help ensure adequate primary frequency response capability.

42. Moreover, as noted above, a number of commenters assert that costs for new generating facilities to install the capability of providing primary frequency response are

[118] IEEE-P1547 Working Group Comments at 1, 5, and 7. Moreover, the Commission notes that other commenters stated costs of installing primary frequency response capability are generally low, but did not differentiate between small and large generating facilities. *See, e.g.*, APPA, *et al.* Comments at 6; California Cities Comments at 2; EEI Comments at 13; Indicated ISOs/RTOs Comments at 3-5; SoCal Edison Comments at 2.

[119] *See* PP 13, 36, *supra*.

[120] IEEE-P1547 Working Group Comments at 1, 5, and 7.

low, suggesting that there is not a financial barrier to small generating facilities installing the capability to provide frequency response.[121] PJM's recent changes to require both small and large non-synchronous generating facilities to use enhanced inverters, which include primary frequency response capability, among other functions, further support this notion.[122]

2. Commission Proposal

43. To remedy the potentially unjust, unreasonable, and unduly discriminatory or preferential practices described above, the Commission preliminarily finds that revisions to the *pro forma* LGIA and *pro forma* SGIA are appropriate. The Commission believes that revising the *pro forma* LGIA and *pro forma* SGIA to require all new generating facilities to install, maintain, and operate a functioning governor or equivalent controls, consistent with the proposed requirements described below, will help to ensure adequate primary frequency response capability as the resource mix continues to evolve, ensure fair and consistent treatment for all types of generating facilities, help balancing authorities meet their frequency response obligations pursuant to NERC Reliability

[121] *See, e.g.*, APPA, *et al.* Comments at 2; EEI Comments at 13; Indicated ISOs/RTOs Comments at 5; SoCal Edison Comments at 2.

[122] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,097 at P 28 (the Commission stated that it "find[s] that PJM's proposal will not present a barrier to non-synchronous resources.").

Standard BAL-003-1.1, and help improve reliability during system restoration and islanding situations.[123]

44. In particular, the Commission proposes to revise the *pro forma* LGIA and *pro forma* SGIA to include the following: (1) requirements for new large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection; (2) requirements for governor or equivalent controls to be operated, at a minimum, with maximum 5 percent droop and ±0.036 Hz deadband settings; (3) requirements to ensure the timely and sustained response to frequency deviations, including provisions to prevent plant-level (i.e., outer-loop) control equipment from inhibiting primary frequency response and resulting in premature withdrawal; and (4) a requirement for droop parameters to be based on nameplate capability with a linear operating range of 59 to 61 Hz. Additionally, as informed by NOI commenters, the Commission believes that it is not necessary to impose a generic headroom requirement or subject newly interconnecting nuclear generating facilities to the new requirements. The Commission does not propose to mandate any separate compensation related to the proposed requirements. The Commission seeks comment on the proposed reforms, as discussed more fully below.

[123] *See* NERC Comments at 17. *See also* NERC Essential Reliability Services Task Force Measures Framework Report at iv.

45. Specifically, the Commission proposes to revise existing sections 9.6 and 9.6.2.1 of the *pro forma* LGIA and to include proposed new sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.3. Similarly, the Commission proposes to revise existing section 1.8 of the *pro forma* SGIA and add proposed new sections 1.8.4, 1.8.4.1, 1.8.4.1.1, 1.8.4.1.2, and 1.8.4.1.3.[124]

46. The Commission's proposed revisions to the *pro forma* LGIA and *pro forma* SGIA would apply to new generating facilities that execute or request the unexecuted filing of interconnection agreements on or after the effective date of any Final Rule issued in Docket No. RM16-6-000. The Commission also proposes to apply the requirements to any large or small generating facility that has an executed or has requested the filing of an unexecuted LGIA or SGIA as of the effective date of any Final Rule in Docket No. RM16-6-000, but that takes any action that requires the submission of a new interconnection request that results in the filing of an executed or unexecuted interconnection agreement on or after the effective date of any Final Rule in Docket No. RM16-6-000.

47. In particular, the proposed revisions to the *pro forma* LGIA and *pro forma* SGIA would require new large and small generating facilities to install, maintain, and operate a functioning governor or equivalent controls, which the Commission proposes to define as the required hardware and/or software that provides frequency responsive real power

[124] The specific proposed modifications and additions to the *pro forma* LGIA and *pro forma* SGIA are set forth at PP 52-53, below.

control with the ability to sense changes in system frequency and autonomously adjust the generating facility's real power output in accordance with the proposed maximum droop and deadband parameters and in the direction needed to correct frequency deviations. The Commission seeks comment on this proposal.

48. The Commission also proposes to require new large and small generating facilities to install, maintain and operate governor or equivalent controls with the ability to operate with a maximum 5 percent droop and ±0.036 Hz deadband parameter, consistent with NERC's recommended guidance. As noted above, the Commission sought comment in the NOI on whether NERC's recommended guidance for governor settings related to droop and deadband should be included in the *pro forma* LGIA and *pro forma* SGIA, and numerous commenters agreed stating that NERC's Guideline provides a sound baseline.[125] Therefore, the Commission preliminarily finds that a maximum droop setting of 5 percent and deadband setting of ±0.036 Hz are appropriate to include in the *pro forma* LGIA and *pro forma* SGIA as interconnection requirements for new generating facilities. The Commission notes that these proposed requirements are *minimum* requirements; therefore, if a new generating facility elects, in coordination with its transmission provider, to operate in a more responsive mode by using lower droop or tighter deadband settings, nothing in these requirements would prohibit it from doing

[125] *See e.g.*, Bonneville Comments at 7; California Cities Comments at 2; IEEE-PES Comments at 2; Indicated ISOs/RTOs Comments at 4; MISO Comments at 4; WIRAB Comments at 7.

so.[126] The Commission seeks comment on these proposed requirements for droop and deadband settings.

49. The Commission also proposes to prohibit all new large and small generating facilities from taking any action that would inhibit the provision of primary frequency response, except under certain conditions as discussed below. The lack of coordination between governor and plant-level control systems can result in premature withdrawal of primary frequency response by allowing additional plant control systems to reverse the action of the governor to return the unit to operating at a pre-selected target set-point.[127] NERC's Guideline explains that "in order to provide sustained primary frequency response, it is essential that the prime mover governor, plant controls and remote plant controls are coordinated."[128] Accordingly, the Commission proposes to require new generating facilities that respond to frequency deviations to not inhibit primary frequency response, such as by coordinating plant-level, outer-loop control equipment with the governor or equivalent controls, except under certain operational constraints including,

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[126] Moreover, the Commission proposes that nothing in these requirements would prohibit the implementation of asymmetrical droop settings (i.e., different droop settings for under-frequency and over-frequency conditions), provided that each segment has a droop value of no more than 5 percent.

[127] NERC Frequency Response Initiative Report at 31. *See also* NOI, 154 FERC ¶ 61,117 at P 49 (stating that primary frequency response withdrawal "has the potential to degrade the overall response of the Interconnection and result in a frequency that declines below the original nadir").

[128] NERC Primary Frequency Control Guideline at 4.

but not limited to, ambient temperature limitations, outages of mechanical equipment, or regulatory requirements. The Commission also proposes to require new generating facilities to respond to frequency deviations without undue delay and to sustain the response until at least system frequency returns to a stable value within the governor's deadband setting. The Commission believes this proposed requirement for sustained response is consistent with the current requirements of PJM and ISO-NE as well as similar OATT revisions recently implemented by CAISO.[129] The Commission seeks comment on the proposed requirements for sustained response. In particular, the Commission seeks comment on whether these provisions will be sufficient to prevent plant-level (i.e., outer-loop) controls from inhibiting primary frequency response.

50. Regarding droop settings, in its comments to the NOI, MISO proposed that a linear droop should be available between 59 to 61 Hz.[130] The Commission believes that this is reasonable because it would allow for new generating facilities that remain connected during frequency deviations to provide a proportional response within this range of frequencies. Accordingly, the Commission proposes to require the droop parameter to be based on the nameplate capability of the unit and linear in operating range between 59 to 61 Hz. The Commission seeks comment on these proposed requirements for droop settings.

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[129] *See, e.g.*, ISO-NE Operating Procedure OP-14 and PJM Manual 14D. *See also CAISO*, 156 FERC ¶ 61,182 at PP 10-12 and 17.

[130] MISO Comments at 4.

51. Several NOI commenters expressed concern about possible generic headroom requirements[131] that could result in significant opportunity costs.[132] The Commission clarifies that nothing in these proposed reforms will impose a generic headroom requirement for new generating facilities or affect the unit commitment and dispatch decisions of balancing authorities. Therefore, if a generating facility that is subject to these proposed requirements has been dispatched by its balancing authority to a set-point at which there is no available operating range to increase or decrease its output in response to frequency deviations, it would not be in violation of the proposed requirements in regards to providing sustained response. The Commission believes that the reliability benefits from the proposed modifications to the *pro forma* LGIA and *pro forma* SGIA do not require imposing additional costs that would result from a generic headroom requirement. The Commission also agrees with NOI commenters regarding the unique operating characteristics and regulatory requirements of nuclear generating facilities regulated by the Nuclear Regulatory Commission, and therefore proposes to exempt such generating facilities from the proposed reforms.[133] The Commission seeks

[131] A generic headroom requirement would require generating facilities to operate below maximum output at all times to ensure sufficient ability to increase their real power output in response to under-frequency conditions.

[132] *See, e.g.*, Apex Comments at 7; Solar City Comments at 1; AWEA Comments at 6.

[133] *See, e.g.*, Nuclear Energy Institute Comments at 1, 4; MISO TOs Comments at 7.

comment on the proposal to not impose a generic headroom requirement and to not apply the new requirements to nuclear generating facilities.

52. In light of the above discussion, the Commission proposes to modify sections 9.6 and 9.6.2.1 of the *pro forma* LGIA and add new sections 9.6.4, 9.6.4.1,9.6.4.2, and 9.6.4.3 as follows:

9.6 Reactive Power and Primary Frequency Response.

9.6.2.1 ~~Governors and~~ Voltage Regulators. Whenever the Large Generating Facility is operated in parallel with the Transmission System ~~and the speed governors (if installed on the generating unit pursuant to Good Utility Practice)~~ and voltage regulators are capable of operation, Interconnection Customer shall operate the Large Generating Facility with its ~~speed governors and~~ voltage regulators in automatic operation. If the Large Generating Facility's ~~speed governors and~~ voltage regulators are not capable of such automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative, and ensure that such Large Generating Facility's reactive power production or absorption (measured in MVARs) are within the design capability of the Large Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Large Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Control Area on a comparable basis.

9.6.4 Primary Frequency Response.

Interconnection Customer shall ensure the primary frequency response capability of its Large Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term "functioning governor or equivalent controls" as used

herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Large Generating Facility's real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating with a maximum 5 percent droop and ±0.036 Hz deadband. The droop characteristic shall be based on the nameplate capacity of the Large Generating Facility, and shall be linear in the range of 59 to 61 Hz. The deadband parameter shall be the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Large Generating Facility's real power output in response to frequency deviations. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Large Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Large Generating Facility with the Transmission System, Interconnection Customer shall operate the Large Generating Facility consistent with provisions specified in Sections 9.6.4.1 and 9.6.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Large Generating Facilities. Nothing in Sections 9.6.4, 9.6.4.1 and 9.6.4.2 shall require the Large Generating Facility to operate above its minimum operating limit or below its maximum operating limit, or otherwise alter its dispatch to have headroom to provide primary frequency response.

9.6.4.1 Governor or Equivalent Controls. Whenever the Large Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Large Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer

shall, in coordination with Transmission Provider, set the deadband parameter to a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider upon request. If Interconnection Customer needs to operate the Large Generating Facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable.

9.6.4.2 Sustained Response. Interconnection Customer shall ensure that the Large Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is provided without undue delay, and ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, outages of mechanical equipment, or regulatory requirements. The Large Generating Facility shall sustain the real power response at least until system frequency returns to a stable value within the deadband setting of the governor or equivalent controls.

9.6.4.3 Exemptions. Large Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 9.6.4, 9.6.4.1, and 9.6.4.2 of this Agreement.

53. Similarly, the Commission proposes to modify section 1.8 of the *pro forma* SGIA and add new sections 1.8.4, 1.8.4.1, 1.8.4.2 and 1.8.4.3 as follows:

1.8 Reactive Power and Primary Frequency Response

1.8.4 Primary Frequency Response. Interconnection Customer shall ensure the primary frequency response capability of its Small Generating Facility by installing,

maintaining, and operating a functioning governor or equivalent controls. The term "functioning governor or equivalent controls" as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Small Generating Facility's real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating with a maximum 5 percent droop and ±0.036 Hz deadband. The droop characteristic shall be based on the nameplate capacity of the Small Generating Facility, and shall be linear in the range of 59 to 61 Hz. The deadband parameter shall be the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Small Generating Facility's real power output in response to frequency deviations. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Small Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Small Generating Facility with the Transmission System, Interconnection Customer shall operate the Small Generating Facility consistent with the provisions specified in Sections 1.8.4.1 and 1.8.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Small Generating Facilities. Nothing in Sections 1.8.4, 1.8.4.1 and 1.8.4.2 shall require the Small Generating Facility to operate above its minimum operating limit, below its maximum operating limit, or otherwise alter its dispatch to have headroom to provide primary frequency response.

1.8.4.1 Governor or Equivalent Controls. Whenever the Small Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Small Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall, in coordination with Transmission Provider, set the deadband parameter to a maximum of ± 0.036 Hz and set the droop parameter to a maximum of 5

> percent. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider upon request. If Interconnection Customer needs to operate the Small Generating facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable.
>
> **1.8.4.2 Sustained Response.** Interconnection Customer shall ensure that the Small Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is provided without undue delay, and ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, outages of mechanical equipment, or regulatory requirements. The Small Generating Facility shall sustain the real power response at least until system frequency returns to a stable value within the deadband setting of the governor or equivalent controls.
>
> **1.8.4.3 Exemptions.** Small Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 1.8.4, 1.8.4.1, 1.8.4.2 of this Agreement.

54. The Commission proposes to apply the primary frequency response requirements to any new large or small generating facility that executes or requests the unexecuted filing of a LGIA or SGIA on or after the effective date of any Final Rule issued in this proceeding. In addition, the Commission proposes to apply the requirements to any large or small generating facility that has an executed or has requested the filing of an unexecuted LGIA or SGIA as of the effective date of any Final Rule in Docket

No. RM16-6-000, but that takes any action that requires the submission of a new interconnection request that results in the filing of an executed or unexecuted interconnection agreement on or after the effective date of any Final Rule in Docket No. RM16-6-000. The Commission seeks comment on the proposed effective date including whether applying these requirements to existing generating facilities that take any action that requires the submission of a new interconnection request that results in the filing of an executed or unexecuted interconnection agreement on or after the effective date of any Final Rule in Docket No. RM16-6-000 would be unduly burdensome.

55. The Commission does not propose in this NOPR to require that the interconnection customer receive any compensation for these proposed requirements. The Commission has previously accepted changes to transmission provider tariffs that similarly required interconnection customers to install primary frequency response capability or that established specified governor settings, without requiring any accompanying compensation.[134] While the Commission has not required compensation for similar requirements in the past, it clarifies that nothing in this NOPR is meant to prohibit a public utility from filing a proposal for primary frequency response compensation under FPA section 205, if it so chooses.[135]

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[134] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,097, at n.58 (2015); *CAISO*, 156 FERC ¶ 61,182, at PP 10-12 and 17 (2016); *New England Power Pool*, 109 FERC ¶ 61,155 (2004), *order on reh'g*, 110 FERC ¶ 61,335 (2005).

[135] 16 U.S.C. 824d (2012).

B. Request for Comment

56. The Commission seeks comment on the proposed: (1) requirements for new large and small generating facilities to install, maintain, and operate a governor or equivalent controls; (2) requirements for droop and deadband settings of 5 percent and ±0.036 Hz, respectively; (3) requirements for timely and sustained response; (4) requirement for droop parameters to be based on nameplate capability with a linear operating range of 59 to 61 Hz; (5) exemptions for new nuclear units; and (6) effective dates as discussed above. The Commission also seeks comment on its proposal to not impose a generic headroom requirement or mandate compensation related to the proposed reforms.

57. In the NOI, the Commission also sought comment on the performance of existing resources and whether primary frequency response requirements for these resources are warranted.[136] At this time, the Commission proposes only to adopt the reforms included in this NOPR regarding newly interconnecting large and small generating facilities. However, the Commission seeks comment regarding whether the reforms proposed in this NOPR are sufficient to ensure adequate levels of primary frequency response, or whether additional reforms are needed. In particular, the Commission seeks comment on whether additional primary frequency response performance or capability requirements for existing resources are needed, and if so, whether the Commission should impose those requirements by: (1) directing the development or modification of a reliability

[136] NOI, 154 FERC ¶ 61,117 at PP 2, 46-52.

standard pursuant to section 215(d)(5) of the FPA; or (2) acting pursuant to section 206 of the FPA to require changes to the *pro forma* OATT.

C. Proposed Compliance Procedures

58. The Commission proposes to require all public utility transmission providers to adopt the requirements of any Final Rule in Docket No. RM16-6-000 as revisions to the LGIA and SGIA in their OATTs within 60 days after the publication of the Final Rule in the Federal Register.

59. Some public utility transmission providers may have provisions in their existing LGIAs and SGIAs that the Commission has found to be consistent with or superior to the *pro forma* LGIA and *pro forma* SGIA. Where these provisions would be modified by the Final Rule, public utility transmission providers must either comply with the Final Rule or demonstrate that these previously-approved variations continue to be consistent with or superior to the *pro forma* LGIA and *pro forma* SGIA as modified by the Final Rule. The Commission also proposes to permit appropriate entities to seek "independent entity variations" from the proposed revisions to the *pro forma* LGIA and *pro forma* SGIA.[137]

60. The Commission would assess whether each compliance filing satisfies the proposed requirements stated above and issue additional orders as necessary to ensure

[137] *See, e.g.*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 827.

that each public utility transmission provider meets the requirements of the subsequent Final Rule.

61. The Commission also proposes that transmission providers that are not public utilities would have to adopt the requirements of this proposal and subsequent Final Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[138]

III. Information Collection Statement

62. The Paperwork Reduction Act (PRA)[139] requires each federal agency to seek and obtain Office of Management and Budget (OMB) approval before undertaking a collection of information directed to ten or more persons, or contained in a rule of general applicability. OMB's regulations require the approval of certain information collection requirements imposed by agency rules.[140] Upon approval of a collection of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this proposal will not be penalized for failing to respond to this collection of information unless the collection of information displays a valid OMB control number. Transmission providers are subject to the proposed revisions to the *pro forma* LGIA and SGIA.

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[138] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760-63.

[139] 44 U.S.C. 3501-3520 (2012).

[140] 5 CFR 1320.11 (2016).

63. In this NOPR, the Commission proposes to amend its *pro forma* LGIA and *pro forma* SGIA in accordance with section 35.28(f)(1) of its regulations.[141] The proposed revisions to the *pro forma* LGIA and *pro forma* SGIA would require new large and small generating facilities to install, maintain, and operate a functioning governor or equivalent controls which the Commission proposes to define as the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the generating facility's real power output in accordance with the proposed maximum droop and dead band parameters and in the direction needed to correct frequency deviations. The NOPR proposes to require each public utility transmission provider to amend its *pro forma* LGIA and *pro forma* SGIA to require that all newly interconnecting large and small generating facilities, as well as all existing large and small generating facilities that take any action that requires the submission of a new interconnection request that results in the filing of an executed or unexecuted interconnection agreement, to adhere to the proposed requirements, on or after the effective date of any Final Rule issued in this proceeding.

64. The reforms in this NOPR would require filings of *pro forma* LGIAs and *pro forma* SGIAs with the Commission. The Commission anticipates the proposed reforms, once implemented, would not significantly change currently existing burdens on an ongoing basis. With regard to those public utility transmission providers that believe

[141] 18 CFR § 35.28(f)(1) (2016).

that they already comply with the proposed reforms in this NOPR, they could demonstrate their compliance in the filing required 60 days after publication of the Final Rule in the Federal Register. The Commission will submit the proposed reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act.[142] The Commission will use FERC-516B as a temporary "placeholder" information collection number.[143]

[142] 44 U.S.C. 3507(d) (2012).

[143] The reporting requirements in this NOPR would normally be included under FERC-516 (OMB Control No. 1902-0096). However, FERC-516 is pending review at OMB in an unrelated action. Because only one item per OMB Control No. can be pending OMB review at a time, the Commission is temporarily using the information collection number FERC-516B (OMB Control No. 1902-0286) to ensure timely submittal of this NOPR to OMB.

Burden Estimate[144]: The Commission believes that the burden estimates below are representative of the average burden on respondents. The estimated burden and cost for the requirements contained in this NOPR follow.[145]

FERC 516B, in NOPR in RM16-6					
	No. of Respondents [146] (1)	**Annual No. of Responses Per Respondent (2)**	**Total No. of Responses (1)*(2)=(3)**	**Average Burden (Hrs.) & Cost ($) Per Response (4)**	**Total Annual Burden Hrs. & Total Annual Cost ($) (3)*(4)=(5)**
LGIA & SGIA changes / revisions	74	1	74	10 hours; $745.00	740 hours; $55,130.00
Total			74		740 hours; $55,130.00

[144] Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, disclose or provide information to or for a Federal agency, including: The time, effort, and financial resources necessary to comply with a collection of information that would be incurred by persons in the normal course of their activities (e.g., in compiling and maintaining business records) will be excluded from the "burden" if the agency demonstrates that he reporting, recordkeeping, or disclosure activities needed to comply are usual and customary.

[145] For this information collection, the Commission staff estimates that industry is similarly situated in terms of hourly cost (wages plus benefits). Based on the Commission's average cost (wages plus benefits) for 2016, the Commission is using $74.50/hour.

[146] The NERC Compliance Registry lists 80 entities that administer a transmission tariff and provide transmission service. The Commission identifies only 74 as being subject to the proposed requirements because 6 are Canadian entities and are not under the Commission's jurisdiction.

There are no maintenance cost, installation cost or any additional cost or requirements after year 1.

Title: FERC-516B, Electric Rate Schedules and Tariff Filings.

Action: Revision of currently approved collection of information.

OMB Control No.: 1902-0286

Respondents for this Rulemaking: Businesses or other for profit and/or not-for-profit institutions.

Frequency of Information: One-time during year 1.

Necessity of Information: The Commission proposes to revise its regulations to require all newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. To implement these requirements, the Commission proposes to revise the *pro forma* LGIA and the *pro forma* SGIA.

Internal Review: The Commission has reviewed the proposed changes and has determined that the changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information collection requirements.

65. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE,

Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director], e-mail: DataClearance@ferc.gov, Phone: (202) 502-8663, fax: (202) 273-0873.

66. Comments on the collection of information and the associated burden estimate in the proposed rule 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], at the following e-mail address: oira_submission@omb.eop.gov. Please refer to OMB Control No. 1902-0286 in your submission.

IV. Environmental Analysis

67. 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.[147] The Commission concludes that neither an Environmental Assessment or an Environmental Impact Statement is required for proposed revisions under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices,

[147] Order No. 486, Regulations Implementing the National Environmental Policy Act, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986-1990 ¶ 30,783 (1987).

contracts and regulations that affect rates, charges, classifications, and services.[148] The revisions proposed in this NOPR update and clarify the application of the Commission's standard interconnection requirements to synchronous and non-synchronous generators. Therefore, this NOPR falls within the categorical exemptions provided in the Commission's regulations, and therefore neither an Environmental Assessment nor an Environmental Impact Statement is required.

V. Regulatory Flexibility Act

68. The Regulatory Flexibility Act of 1980 (RFA)[149] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. The RFA does not mandate any particular outcome in a rulemaking. It only requires consideration of alternatives that are less burdensome to small entities and an agency explanation of why alternatives were rejected.

69. The Small Business Administration (SBA) revised its size standards (effective January 22, 2014) for electric utilities from a standard based on megawatt hours to a standard based on the number of employees, including affiliates. Under SBA's standards, some transmission owners will fall under the following category and

[148] 18 CFR 380.4(a)(15) (2015).

[149] 5 U.S.C. 601-612 (2012).

associated size threshold: electric bulk power transmission and control, at 500 employees.[150]

70. The Commission estimates that the total number of transmission providers, both public and non-public, affected by this NOPR is 74.[151] Of these, the Commission estimates that approximately 27.5 percent are small entities. The Commission estimates the average total cost to each of these entities will be minimal, requiring on average 10 hours, or $745.00. According to SBA guidance, the determination of significance of impact "should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors."[152] The Commission does not consider the estimated burden to be a significant economic impact. As a result, the Commission believes this NOPR would not have a significant economic impact on a substantial number of small entities.

71. The Commission estimates that the total annual number of new non-synchronous interconnections per year for the first few years of potential implementation under this

[150] 13 CFR 121.201, Sector 22 (Utilities), NAICS code 221121 (Electric Bulk Power Transmission and Control).

[151] The NERC Compliance Registry lists 80 entities that administer a transmission tariff and provide transmission service. The Commission identifies only 74 as being subject to the proposed requirements because 6 are Canadian entities and are not under the Commission's jurisdiction.

[152] U. S. Small Business Administration, *A Guide for Government Agencies How to Comply with the Regulatory Flexibility Act*, at 18 (May 2012), https://www.sba.gov/sites/default/files/advocacy/rfaguide_0512_0.pdf.

NOPR would be approximately 200, representing approximately 5,000 MW of installed capacity. Of these, the Commission estimates that the majority are small entities. The Commission estimates the average total cost to each of these entities will be minimal, requiring on average approximately $3,300 per MW of installed capacity. According to SBA guidance, the determination of significance of impact "should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors." The Commission does not consider the estimated burden to be a significant economic impact on these entities because the cost is relatively minimal compared to the average capital cost per MW for wind and solar PV generation.[153] Additionally, the Commission does not believe that there will be substantial additional costs for new synchronous generators because synchronous generators already come equipped with governors that provide the capability to provide primary frequency response. Accordingly, the Commission believes that this NOPR would not have a significant economic impact on a substantial number of small entities.

VI. Comment Procedures

72. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative

[153] LBNL estimates that capital cost per MW of installed wind capacity is $1,690,000. *See* LBNL 2015 Wind Market Report (Aug. 2016), https://emp.lbl.gov/sites/all/files/2015-windtechreport.final_.pdf). NREL estimates that the capital cost per MW of installed solar PV capacity is $1,770,000. *See* NREL U.S. Photovoltaic Prices and Cost Breakdowns (Sep. 2015), http://www.nrel.gov/docs/fy15osti/64746.pdf.

proposals that commenters may wish to discuss. Comments are due [**INSERT DATE 60 days after publication in the FEDERAL REGISTER**]. Comments must refer to Docket No. RM16-6-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

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

74. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426.

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

VII. Document Availability

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 contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal

business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

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

78. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or 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.

By direction of the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix

List of Commenters (Docket No. RM16-6-000)

AES Companies	AES Corporation/AES Energy Storage/Dayton Power and Light Company/Indianapolis Power and Light Company
APPA, et al.	American Public Power Association/Large Public Power Council/ Transmission Access Policy Study Group
AWEA	American Wind Energy Association
Apex	Apex Compressed Air Energy Storage
APS	Arizona Public Service Company
Bonneville	Bonneville Power Administration
CAISO	California Independent System Operator
Chelan County	Chelan County Public Utility District
California Cities	City of Anaheim/City of Azusa/City of Banning/City of Colton/City of Pasadena/ City of Riverside
EEI	Edison Electric Institute
EDP	EDP Renewables North America
EPRI	Electric Power Research Institute
EPSA, et al.	Electric Power Supply Association/Independent Power Producers of New York/New England Power Generators Association/Western Power Trading Forum
ELCON	Electricity Consumers Resource Council
ESA	Energy Storage Association
Grid Storage Consulting	Grid Storage Consulting
Howard F. Illian	Howard F. Illian
Idaho Power	Idaho Power Company
Indicated ISOs/RTOs	Independent Electricity System Operator/ISO New England/ New York Independent System Operator/PJM Interconnection/ Southwest Power Pool
IEEE-P1547 Working Group	Institute of Electrical and Electronics Engineers (IEEE) P1547 Standards Working Group
IEEE-PES	IEEE Power and Energy Society Technical Council
ITC, et al.	International Transmission Company/Michigan Electric Transmission Company/ITC Great Plains/ITC Midwest
Manitoba	Manitoba Hydro
Microgrids Resources Coalition	Microgrids Resources Coalition

MISO	Midcontinent Independent System Operator
MISO TOs	Midcontinent Independent System Operator Transmission Owners
NARUC	National Association of Regulatory Utility Commissioners
NRECA	National Rural Electric Cooperative Association
NERC	North American Electric Reliability Corporation
North American Generator Forum	North American Generator Forum
Nuclear Energy Institute	Nuclear Energy Institute
PG&E	Pacific Gas and Electric Company
Peak Reliability	Peak Reliability
PJM Utilities Coalition	PJM Utilities Coalition
Powerex	Powerex Corp.
Public Interest Organizations	Public Interest Organizations
Ralph D. Masiello	Ralph D. Masiello
SDG&E	San Diego Gas & Electric Company
Solar City	Solar City Corporation
SoCal Edison	Southern California Edison Company
Southern Company	Southern Company
Steel Producers	Steel Producers
Tacoma Power	Tacoma Power
TVA	Tennessee Valley Authority
Tri-State Generation	Tri-State Generation and Transmission Association
Union of Concerned Scientists	Union of Concerned Scientists
WIRAB	Western Interconnection Regional Advisory Body

20161121-3022 FERC PDF (Unofficial) 11/21/2016

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events

Docket No. RM15-11-001

ORDER GRANTING REHEARINGS FOR FURTHER CONSIDERATION

(November 21, 2016)

Rehearings have been timely requested of the Commission's order issued on September 22, 2016, in this proceeding. *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, 156 FERC ¶ 61,215 (2016). In the absence of Commission action within 30 days from the date the rehearing requests were filed, the request for rehearing (and any timely requests for rehearing filed subsequently)[1] would be deemed denied. 18 C.F.R. § 385.713 (2016).

In order to afford additional time for consideration of the matters raised or to be raised, rehearing of the Commission's order is hereby granted for the limited purpose of further consideration, and timely-filed rehearing requests will not be deemed denied by operation of law. Rehearing requests of the above-cited order filed in this proceeding will be addressed in a future order. As provided in 18 C.F.R. § 385.713(d), no answers to the rehearing requests will be entertained.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[1] *See San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange*, 95 FERC ¶ 61,173 (2001) (clarifying that a single tolling order applies to all rehearing requests that were timely filed).

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Document Content(s)

RM15-11-001.DOC.....1-1

157 FERC ¶ 61,116
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Parts 375 and 388

[Docket No. RM17-5-000; Order No.832]

Regulations Implementing the FOIA Improvement Act of 2016 and Clarifying the FOIA Regulations

(Issued November 17, 2016)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: On June 30, 2016, President Obama signed the Freedom of Information Act Improvement Act of 2016. The Act requires agencies to revise their regulations within 180 days to account for the new statutory mandates. After undertaking a review of Commission regulations in accordance with Section 3 of the Act, the Commission is revising its FOIA regulations to incorporate the statutory mandates. Additionally, this rule updates the delegation regulations with respect to determinations made by the General Counsel in response to FOIA administrative appeals.

DATE: This rule will become effective **[Insert_Date 30 days after publication in the FEDERAL REGISTER]**.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

157 FERC ¶ 61,116
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, and Colette D. Honorable.

Regulations Implementing the FOIA Improvement Act of 2016 and Clarifying the FOIA Regulations.	Docket No. RM17-5-000

ORDER NO. 832

FINAL RULE

(Issued November 17, 2016)

I. Introduction

1. On June 30, 2016, President Obama signed the Freedom of Information Act (FOIA) Improvement Act of 2016 (FOIA Improvement Act or the Act).[1] The Act directs agencies to: (1) make information that has been requested and disclosed three times publically accessible in an electronic format;[2] (2) institute a sunset period of 25 years on records protected under the deliberative process privilege; (3) codify the Department of

[1] FOIA Improvement Act of 2016, Pub. L. 114-185, 130 Stat. 538 (June 2016). The Act also requires several actions that do not necessitate a revising of the regulations such as FOIA officers offering additional FOIA training.

[2] *See* Proactive Disclosure of Non-Exempt Agency Information: Making Information Available Without the Need to File a FOIA Request, OIP Guidance (Oct. 5, 2015), https://www.justice.gov/oip/oip-guidance-5.

Justice's foreseeability of harm standard when rendering FOIA determinations;[3] (4) take reasonable steps to segregate exempt information from nonexempt information; (5) limit fees in unusual circumstances when the agency response is delayed; and (6) provide additional notice requirements to FOIA requesters in agency determination letters.

2. Section 3 of the Act requires agencies to revise their regulations to account for the new statutory mandates. The Act provides that agencies must revise their rules within 180 days to incorporate the statutory changes. Accordingly, the Commission is revising its regulations to implement the FOIA Improvement Act. Consistent with the FOIA administrative appeal provisions in section 388.110, the Commission also is clarifying under section 375.309 that the General Counsel or a designee may issue final determinations on administrative FOIA appeals.

II. Discussion

3. After undertaking a review of Commission regulations in accordance with Section 3 of the Act, the Commission is revising its FOIA regulations in 18 CFR sections 388.106-10 (2016), as follows.

[3] *See* 5 U.S.C. 552(b)(5)(2012) (incorporating various privileges including the deliberative process privilege covering "inter-agency or intra-agency memorandums or letters which would not be available by law to a party other than an agency in litigation with the agency.")

A. Revisions to Section 375.309

4. The FOIA administrative appeal provisions in section 388.110 provide that a FOIA administrative appeal must be directed to the General Counsel for determination, and that the General Counsel or the General Counsel's designee will make a determination on that appeal within the statutory timeframe.[4] Consistent with the Commission's FOIA administrative appeal provisions in section 388.110, the Commission is clarifying, in section 375.309, that the General Counsel or a designee will provide determinations in response to FOIA administrative appeals.

B. Revisions to Section 388.106

5. The FOIA Improvement Act requires agencies to "make available for public inspection in an electronic format" records that have been released and "that have been requested 3 or more times." Section 388.106 concerns Commission records available in the public reference room at the Commission's headquarters or on the Commission's website. The Commission is revising that section to codify this requirement.

C. Revisions to Section 388.107

6. The FOIA Improvement Act provides that the deliberative process privilege no longer exempts a document that is 25 years or older. Section 388.107 describes material that is exempt from public disclosure under the Commission's regulations, and a provision in that section describes material that would traditionally fall under the

[4] *See* 5 U.S.C. 552(a)(6)(A)(ii) (2012).

protection of deliberative process privilege. The Commission is revising section 338.107(e) to reflect the 25 year limitation on material that would otherwise be exempt under the deliberative process privilege.

D. Revisions to Section 388.108

7. The FOIA Improvement Act requires agencies to codify the Department of Justice's foreseeable harm standard. Under that standard, agencies "shall withhold information" under the FOIA "only if the agency reasonably foresees that disclosure would harm an interest protected by an exemption" or "disclosure is prohibited by law." The standard does not require the release of material "that is otherwise prohibited from disclosure by law, or otherwise exempted from disclosure under [Exemption] 3." The Act also directs agencies to make reasonable efforts to segregate and release nonexempt material. Consistent with Section 3 of the Act, the Commission revises section 388.108 to codify these practices.

E. Revisions to Section 388.109

8. The Act directs agencies to waive processing fees, under certain unusual circumstances, where the agency's response was delayed.[5] The Commission is revising

[5] *See* Prohibition on Assessing Certain Fees When the FOIA's Time Limits Are Not Met, OIP Guidance (Oct. 19, 2016), https://www.justice.gov/oip/oip-guidance/prohibition_on_assessing_certain_fees_when_foia_time_limits_not_met.

its regulations on FOIA processing fees, section 388.109, to provide for fee waivers in the unusual circumstances described in the Act.

F. Revisions to Section 388.110

9. The FOIA Improvement Act also provides changes to administrative appeals and provides mandatory language that must go in initial response letters. The Act requires that all determination letters must notify the requester that they can seek assistance from the FOIA Public Liaison. Each adverse FOIA determination letter must notify the requester of the option to seek dispute resolution services from Office of Government Information Services (OGIS).

10. The Act also directs Agencies to extend the timeframe to file an administrative appeal from 45 days to at least 90 days. Additionally, the Act mandates that agencies advise requesters that they may seek the assistance of OGIS when the agency extends the response time by ten or more days for unusual circumstances. The Commission will take these steps and revises section 388.110 of its regulations to codify this practice.

III. Information Collection Statement

11. Office of Management and Budget (OMB) regulations require OMB to approve certain information collection requirements imposed by agency rule.[6] However, this instant Final Rule does not contain any information collection requirements. Therefore, compliance with OMB regulations is not required.

[6] 5 CFR 1320.12 (2016).

IV. Environmental Analysis

12. 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.[7] Issuance of this Final Rule does not represent a major federal action having a significant adverse effect on the human environment under the Commission's regulations implementing the National Environmental Policy Act of 1969. Part 380 of the Commission's regulations lists exemptions to the requirement to draft an Environmental Analysis or Environmental Impact Statement. Included is an exemption for procedural, ministerial, or internal administrative actions.[8] This rulemaking is exempt under that provision.

V. Regulatory Flexibility Act

13. The Regulatory Flexibility Act of 1980 (RFA)[9] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. This Final Rule makes procedural modifications as directed by statute. The Commission certifies that it will not have a significant economic impact

[7] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, (Dec. 17, 1987), FERC Stats. & Regs. ¶ 30,783 (1987).

[8] 18 CFR 380.4(a)(1) (2016).

[9] 5 U.S.C. 601-12 (2012).

upon participants in Commission proceedings. An analysis under the RFA is not required.

VI. Document Availability

14. In addition to publishing the full text of this document in the *Federal Register*, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

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

16. User assistance is available for eLibrary and the Commission'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

17. The Commission is issuing this rule as a Final Rule without a period for public comment. Under 5 U.S.C. 553(b)(3)(A), notice and comment procedures are unnecessary for "interpretative rules, general statements of policy, or rules of agency organization, procedure, or practice . . ." This rule merely makes modification to existing procedures as directed by statute. The rule will not significantly affect regulated entities or the general public.

18. These regulations are effective [**insert date 30 days after publication in the *Federal Register***].

List of Subjects in 18 CFR Part 375

Authority delegations (Government agencies); Seals and insignia; Sunshine Act.

List of Subjects in 18 CFR Part 388

Confidential business information; Freedom of information.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

In consideration of the foregoing, the Commission amends Parts 375 and 388, Chapter 1, Title 18, Code of Federal Regulations, as follows:

PART 375— THE COMMISSION

1. The authority citation for part 375 continues to read as follows:

Authority: 5 U.S.C. 551-557; 15 U.S.C. 717-717w, 3301-3432; 16 U.S.C. 791-825r, 2601-2645; 42 U.S.C. 7101-7352.

2. In section 375.309, Paragraph (h) is added as follows

Section 375.309 Delegations to the General Counsel.

* * * * *

(i) Deny or grant, in whole or in part, an appeal of a Freedom of Information Act determination by the Director of the Office of External Affairs.

PART 388— INFORMATION AND REQUESTS

1. The authority citation for part 388 continues to read as follows:

Authority: 5 U.S.C. 301-305, 551, 552 (as amended), 553-557; 42 U.S.C. 7101-7352.

2. Amend section 388.106 by adding paragraph (a)(24), to read as follows

Section 388.106 Requests for Commission records available in the Public Reference Room and from the Commission's web site, *http://www.ferc.gov*.

* * * * *

(a) * * *

(24) Records that have been requested three or more times and determined eligible for public disclosure will be made publicly available on the Commission's website or through other electronic means.

* * * * *

3. Amend section 388.107 by revising paragraph (e), to read as follows

Section 388.107 Commission records exempt from public disclosure.

* * * * *

(e) Interagency or intraagency memoranda or letters which would not be available by law to a party other than an agency in litigation with the agency, except that the deliberative process privilege shall not exempt any record 25 years or older.

* * * * *

4. Amend section 388.108 by revising paragraph (c) to read as follows:

Section 388.108 Requests for Commission records not available through the Public Reference Room (FOIA requests).

* * * * *

(c) * * *

(4) The Director will consider whether partial disclosure of information is possible whenever it is determined that a document is exempt and will take reasonable steps to segregate and release nonexempt information.

(5) The Director will only withhold information where it is reasonably foreseeable that disclosure would harm an interest protected by an exemption or disclosure is prohibited by law or otherwise exempted from disclosure under FOIA Exemption 3.

***

5. Amend section 388.109 by adding paragraph (f), to read as follows

Section 388.109 Fees for record requests.

* * * * *

(f) The Commission will not charge search fees (or duplication fees for requesters with preferred fee status) where, after extending the time limit for unusual circumstances, as described in section 388.110, the Director does not provide a timely determination.

(1) If there are unusual circumstances, as described in Section 388.110, and there are more than 5,000 responsive pages to the request, the Commission may charge search fees (or, for requesters in preferred fee status, may charge duplication fees) where the requester received timely written notice and the Commission has discussed with the requester via written mail, electronic mail, or telephone (or made not less than 3 good-faith attempts to do so) how the requester could effectively limit the scope of the request; or

(2) If a court determines that exceptional circumstances exist, the Commission's failure to comply with a time limit will be excused for the length of time provided by the court order.

6. Amend section 388.110 by revising paragraphs (a) and (b) to read as follows:

Section 388.110 Procedure for appeal of denial of requests for Commission records not publicly available or not available through the Public Reference Room, denial of...fee waiver or reduction, and denial of requests for expedited processing.

* * * * *

(a) (1) Determination letters shall indicate that a requester may seek assistance from the FOIA Public Liaison. A person whose request for records, request for fee waiver, or request for expedited processing is denied in whole or in part may seek dispute resolution services from the Office of Government Information Services, or may appeal the determination to the General Counsel or General Counsel's designee within 90 days of the determination.

(2) Appeals filed pursuant to this section must be in writing, addressed to the General Counsel of the Commission, and clearly marked "Freedom of Information Act Appeal." Such an appeal received by the Commission not addressed and marked as indicated in this paragraph will be so addressed and marked by Commission personnel as soon as it is properly identified and then will be forwarded to the General Counsel. Appeals taken pursuant to this paragraph will be considered to be received upon actual receipt by the General Counsel.

(3) The General Counsel or the General Counsel's designee will make a determination with respect to any appeal within 20 working days after the receipt of such appeal. An appeal of the denial of expedited processing will be considered as expeditiously as possible within the 20 working day period. If, on appeal, the denial of the request for

records, fee reduction, or expedited processing is upheld in whole or in part, the General Counsel or the General Counsel's designee will notify the person making the appeal of the provisions for judicial review of that determination.

(b) * * *

(5) Whenever the Commission extends the time limit, pursuant to (b)(1) of this paragraph, by more than ten additional working days, the written notice will notify the requester of the right to seek dispute resolution services from the Office of Government Information Services.

157 FERC ¶ 61,123
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Parts 375 and 388

[Docket Nos. RM16-15-000 and RM15-25-001; Order No. 833]

Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information; Availability of Certain North American Electric Reliability Corporation Databases to the Commission

(Issued November 17, 2016)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) amends its regulations to implement provisions of the Fixing America's Surface Transportation Act that pertain to the designation, protection and sharing of Critical Electric Infrastructure Information. Additionally, the Commission amends its regulations addressing Critical Energy Infrastructure Information.

EFFECTIVE DATE: This rule will become effective **[INSERT DATE 60 days after publication in the FEDERAL REGISTER].**

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SUPPLEMENTARY INFORMATION:

157 FERC ¶ 61,123
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, and Colette D. Honorable.

Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information	Docket Nos. RM16-15-000
Availability of Certain North American Electric Reliability Corporation Databases to the Commission	RM15-25-001

ORDER NO. 833

FINAL RULE

(Issued November 17, 2016)

1. The Commission amends 18 CFR sections 375.309, 375.313, 388.112 and 388.113 of its regulations to implement the requirements of the Fixing America's Surface Transportation (FAST) Act as set forth in section 215A(d)(2) of the Federal Power Act (FPA).[1] The Commission also amends its existing Critical Energy Infrastructure Information procedures. These changes are intended to comply with the FAST Act as well as improve the overall efficiency of the Commission's procedures for certain

[1] Fixing America's Surface Transportation Act, Pub. L. No. 114-94, § 61,003, 129 Stat. 1312, 1773-1779 (2015) (to be codified at 16 U.S.C. 824 *et seq.*) (FAST Act).

infrastructure information that is submitted to, or generated by, the Commission. The amended procedures will be referred to as the Critical Energy/Electric Infrastructure Information (CEII) procedures.

I. Background

A. Critical Energy Infrastructure Information Regulations

2. Shortly after September 11, 2001, the Commission took steps to protect information that it considered Critical Energy Infrastructure Information.[2] As a preliminary step, the Commission removed documents from its public files and eLibrary database that were likely to contain detailed specifications about critical infrastructure. The Commission directed the public to use the Freedom of Information Act (FOIA) request process to obtain such information.[3] Given that such information would typically be exempt from mandatory disclosure pursuant to FOIA, the Commission determined that it was important to have a process for individuals with a valid or legitimate need to access certain sensitive energy infrastructure information. Thus, in 2003, the Commission

[2] *See Statement of Policy on Treatment of Previously Public Documents*, 97 FERC ¶ 61,030 (2001).

[3] 5 U.S.C. 552 *as amended by* the FOIA Improvement Act of 2016, Pub. L. No. 114-185, 130 Stat. 538 (2016); 18 CFR 388.108 (Requests for Commission records not available through the Public Reference Room (FOIA Requests)).

issued a final rule establishing Critical Energy Infrastructure Information regulations.[4]

3. Each year, over 7,000 documents are submitted to the Commission's eLibrary system as Critical Energy Infrastructure Information. The Commission also receives approximately 200 requests for Critical Energy Infrastructure Information each year. Requests for Critical Energy Infrastructure Information are submitted by, among others, public utilities, gas pipelines, Liquefied Natural Gas (LNG) facilities, hydroelectric developers, academics, landowners, public interest groups, researchers, renewable energy organizations, consultants, and federal agencies.

4. The Commission's current Critical Energy Infrastructure Information process is designed to limit the distribution of sensitive infrastructure information to those individuals with a need to know in order to avoid having sensitive information fall into the hands of those who may use it to attack the Nation's infrastructure.

B. FAST Act

5. On December 4, 2015, the President signed the FAST Act into law. The FAST Act, *inter alia*, added section 215A to the Federal Power Act to improve the security and resilience of energy infrastructure in the face of emergencies. The FAST Act directs the Commission to issue regulations aimed at securing and sharing sensitive infrastructure

[4] *Critical Energy Infrastructure Information*, Order No. 630, FERC Stats. & Regs. ¶ 31,140, *order on reh'g*, Order No. 630-A, FERC Stats. & Regs. ¶ 31,147 (2003).

information. Specifically, FPA section 215A(d)(2) (Designation and Sharing of Critical Electric Infrastructure Information) requires the Commission to "promulgate such regulations as necessary to":

> (A) establish criteria and procedures to designate information as critical electric infrastructure information;
>
> (B) prohibit the unauthorized disclosure of critical electric infrastructure information;
>
> (C) ensure there are appropriate sanctions in place for Commissioners, officers, employees, or agents of the Commission or the Department of Energy [DOE] who knowingly and willfully disclose critical electric infrastructure information in a manner that is not authorized under this section; and
>
> (D) taking into account standards of the Electric Reliability Organization, facilitate voluntary sharing of critical electric infrastructure information with, between, and by – (i) Federal, State, political subdivision, and tribal authorities; (ii) the Electric Reliability Organization; (iii) regional entities; (iv) information sharing and analysis centers established pursuant to Presidential Decision Directive 63; (v) owners, operators, and users of critical electric infrastructure in the United States; and (vi) other entities determined appropriate by the Commission.[5]

C. Notice of Proposed Rulemaking

6. On June 16, 2016, the Commission issued a Notice of Proposed Rulemaking (NOPR) to amend its regulations to implement the provisions of the FAST Act pertaining

[5] FAST Act, Pub. L. No. 114-94, section 61,003, 129 Stat. 1312, 1776.

to the designation, protection and sharing of CEII.[6] The proposed amendments included, among other things, the creation of criteria and procedures for designating information as CEII; a specific prohibition on unauthorized disclosure of that information; sanctions for knowing and willful wrongful disclosure of CEII by certain federal personnel; a process for voluntary sharing of CEII; and changes to the existing process for requesting CEII. In response to the NOPR, nineteen entities filed comments and two entities filed reply comments. The Appendix to this Final Rule lists the entities that submitted comments in response to the NOPR.

II. Discussion

7. The Commission adopts the majority of amendments proposed in the NOPR. The Commission determines that the amendments comply with the requirements of the FAST Act and better ensure the secure treatment of CEII. In addition, as discussed below, the Commission modifies or otherwise clarifies certain proposals made in the NOPR based on our review of the comments. In the discussion below, we address the following issues regarding the CEII amendments: (A) scope, purpose, and definitions; (B) criteria and procedures for determining what constitutes CEII; (C) duty to protect CEII; (D) sanctions

[6] *Regulations Implementing FAST Act Section 61003 – Critical Infrastructure Security and Amending Critical Energy Information*, 81 FR 43,557 (July 5, 2016), 155 FERC ¶ 61,278 (2016) (NOPR).

for unauthorized disclosure of CEII; (E) voluntary sharing of CEII; and (F) requests for access to CEII.

A. Scope, Purpose, and Definitions

NOPR

8. In the NOPR, the Commission proposed to amend section 388.113 to include procedures for submitting, designating, handling, sharing and disseminating Critical Electric Infrastructure Information submitted to or generated by the Commission.[7] The Commission proposed to define the term "Critical Electric Infrastructure Information"[8] to include "Critical Energy Infrastructure Information" as defined under the Commission's

[7] NOPR, 155 FERC ¶ 61,278 at P 10.

[8] *Id.* P 11. Section 215A(a)(3) of the FAST Act defines Critical Electric Infrastructure Information to mean:

> [I]nformation related to critical electric infrastructure, or proposed critical electrical infrastructure, generated by or provided to the Commission or other Federal agency other than classified national security information, that is designated as critical electric infrastructure information by the Commission or the Secretary of the Department of Energy pursuant to subsection (d). Such term includes information that qualifies as critical energy infrastructure information under the Commission's regulations. Critical Electric Infrastructure Information is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552, pursuant to section 215A(d)(1)(A) of the Federal Power Act.

current regulations and to refer to both types of information, collectively, as CEII.[9] The Commission also proposed to delete references to CEII in section 388.112 so that section 388.112 would only address privileged material and all procedures regarding CEII would be in section 388.113.

Comments

9. APPA and MISO maintain that CEII should not include all Critical Energy Infrastructure Information.[10] APPA contends that Congress intended for the Commission to develop a separate process for Critical Electric Infrastructure Information regarding the bulk-power system and that the amended regulations fall "short" of Congress's intent under the FAST Act because the amended regulations include the voluntary disclosure provisions found in the Commission's current regulations.[11] APPA also asserts that the proposed definition of "critical electric infrastructure" "does not comport well" with section 215A(d)(10) of the FPA, which provides DOE and the Commission with the authority to remove the CEII designation from information regarding the bulk-power system or distribution facilities.[12] MISO contends that the Commission misinterpreted

[9] NOPR, 155 FERC ¶ 61,278 at P 13.

[10] *See* APPA Comments at 5-11; MISO Comments at 5.

[11] APPA Comments at 5, 9, 13.

[12] Section 215A(d)(10) of the FPA provides that when "the Commission or the [DOE] Secretary, as appropriate, determines that the unauthorized disclosure of such

(continued…)

the definition of Critical Electric Infrastructure Information and that not all "Critical Energy Infrastructure Information under the Commission's regulations is included" in the definition of Critical Electric Infrastructure Information.[13]

10. TAPS and APPA maintain that the Commission should revise the CEII definition to include additional language from the FAST Act. Specifically, TAPS and APPA recommend that the proposed definition of CEII incorporate section 215A(d)(1)(B), which provides that CEII "shall not be made available by any Federal, State, political subdivision or tribal authority pursuant to any Federal, State, political subdivision or tribal law requiring public disclosure of information or records."[14] APPA requests that, if the Commission includes Critical Energy Infrastructure Information in CEII, then the Commission should interpret section 215A(d)(1)(B) to apply to all forms of CEII, including Critical Energy Infrastructure Information.[15] TAPS and APPA also request that the Commission define the term "political subdivision," as used in section 215A(d)(1)(B), to have the same meaning as the term "political subdivision" in section 201(f) of the FPA, such that the term in section 215A(d)(1)(B) would include any agency,

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information could no longer be used to impair the security or reliability of the bulk-power system or distribution facilities" the designation shall be removed.

[13] MISO Comments at 4-6.

[14] TAPS Comments at 8; APPA Comments at 21-22.

[15] APPA Comments at 23.

authority or instrumentality of any political subdivision or owned by a political subdivision.[16] TAPS and APPA contend that, absent the clarification, these additional entities may not be considered a "political subdivision" under State laws.[17]

11. TAPS recommends that the Commission delete from the definition of Critical Energy Infrastructure Information the requirement that such information be exempt from FOIA.[18] TAPS contends that the existing exemption clause is unnecessary because any materials will be exempt from FOIA pursuant to section 215A(d)(1)(A).[19]

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[16] TAPS Comments at 8; APPA Comments at 22. Section 201(f) provides that:

> No provision in this subchapter shall apply to, or be deemed to include, the United States, a State or any political subdivision of a State, an electric cooperative that receives financing under the Rural Electrification Act of 1936 (7 U.S.C. 901 et seq.) or that sells less than 4,000,000 megawatt hours of electricity per year, or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing, or any officer, agent, or employee of any of the foregoing acting as such in the course of his official duty, unless such provision makes specific reference thereto.

16 U.S.C. 824(f)

[17] TAPS Comments at 8-9; APPA Comments at 22-23.

[18] TAPS Comments at 4-5.

[19] *Id.* at 4.

12. Other commenters seek clarification on the scope of the CEII definition. Specifically, the Trade Associations request that the Commission clarify whether the name or location of an electric system, asset, owner or operator could be protected under the proposed CEII definition.[20] NRECA, similarly, urges the Commission to clarify that material considered Critical Energy Infrastructure Information, such as electric generation, and non-bulk electric system transmission and distribution facilities, would still qualify as CEII under the revised definition in the amended regulations.[21]

13. Powerex requests that the Commission specify whether the new definition of CEII expands the scope of information currently defined as Critical Energy Infrastructure Information.[22] Powerex contends that the scope of this proceeding should remain limited to CEII regulations and procedures discussed in the NOPR and, thus, the scope of this proceeding should not extend to other forms of sensitive data.[23] Powerex, further, explains that there may be a tendency to over-designate information as CEII and, therefore, the Commission should recognize that transparency is needed to balance CEII

[20] Trade Associations Comments at 16.

[21] NRECA Comments at 7.

[22] Powerex Comments at 11.

[23] *Id*. at 15.

protection against the due process rights of parties participating in Commission proceedings.[24]

14. TAPS, APPA and the Trade Associations recommend revisions to the CEII Non-Disclosure Agreements (NDA).[25] Specifically, TAPS, APPA, and the Trade Associations state that the Commission should expressly incorporate the language from section 215A(d)(1)(B), exempting CEII from public disclosure, into the NDA.[26] TAPS requests that the Commission eliminate the State Agency NDA. TAPS contends that "[p]rior to the FAST Act's express preemption of Sunshine Laws requiring disclosure," the State Agency NDA was an attempt to impose a contractual nondisclosure requirement for critical energy infrastructure information provided to a State agency. TAPS maintains that, once section 215A(d)(1)(B) is included in the general NDA, the State Agency NDA should be eliminated because it is now unnecessary.[27]

15. With respect to the proposed edits to sections 388.112 and 388.113 to separate the Commission's treatment of privileged material from the Commission's treatment of CEII,

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[24] *Id.* at 12.

[25] APPA Comments at 23; TAPS Comments at 9-10; Trade Associations Comments at 32.

[26] *See id.*

[27] TAPS Comments at 10; *see also* Critical Energy Infrastructure Information State Agency Employee Non-Disclosure Agreement, http://www.ferc.gov/legal/ceii-foia/ceii/state-agen-nda.pdf.

MISO suggests that the title for section 388.112 be changed to "Submission and treatment of privileged information" and section 388.113 be changed to "Submission and treatment of Critical Electric Infrastructure Information (CEII)."[28]

16. The Trade Associations request that the Commission expressly state in the amended regulations that the CEII process is not intended to, and should not be interpreted to, supersede or otherwise affect existing laws, regulations, and agency rules that separately safeguard such data.[29]

Commission Determination

17. As discussed below, the Commission, with limited modifications, adopts the amendments proposed in the NOPR addressing the scope, purpose and definitions in the CEII regulations. The Commission determines that the amendments are consistent with the requirements of the FAST Act and will result in more secure treatment of CEII.

18. The Commission disagrees with APPA and MISO that the CEII definition should not include Critical Energy Infrastructure Information and that there should be separate processes for electric and non-electric CEII. Our determination is based on the plain language of the FAST Act. Section 215A(a)(3) defines Critical Electric Infrastructure Information to "include information that qualifies as critical energy infrastructure

[28] MISO Comments at 3.

[29] *See* Trade Associations Comments at 26.

information under the Commission's regulations."[30] In subsuming the Commission's existing Critical Energy Infrastructure Information within section 215A's CEII definition, Congress expressly stated that the definition of CEII includes Critical Energy Infrastructure Information. There is no indication in the language of the FAST Act that Congress intended to limit the types of Critical Energy Infrastructure Information to only electric infrastructure information.[31]

19. Including Critical Energy Infrastructure Information within the definition of CEII is not inconsistent with the provisions of section 215A(d)(10), as APPA maintains. First, section 215A(d)(10) states that removal of a CEII designation may be appropriate when the disclosure of such information "could no longer be used to impair the security or reliability of the bulk-power system *or distribution facilities*." (Emphasis supplied.) Thus, it is clear that Congress did not intend for the new Critical Electric Infrastructure Information designation to apply only to the bulk-power system. Second, Critical Energy Infrastructure Information includes information that "relates details about the production,

[30] FAST Act, Pub. L. No. 114-94, section 61,003, 129 Stat. 1312, 1776.

[31] For the same reason, we reject MISO's recommendation that the title for section 388.112 should be changed to "Submission and treatment of privileged information" and that the title for section 388.113 should be changed to "Submission and treatment of Critical Energy Infrastructure Information (CEII)." MISO Comments at 3.

generation, transportation, transmission, or distribution of energy."[32] Such information, even if it concerns non-electric infrastructure, could be used to impair the security or reliability of the bulk-power system, for example by severing gas pipeline connections to electric generation facilities.

20. Moreover, the Commission determines that a single CEII process for Critical Energy/Electric Infrastructure Information is the most efficient way to fulfill the statutory mandate of the FAST Act and to avoid any confusion that could result from different processes for different types of critical infrastructure information.[33] Absent contrary language in the FAST Act, the Commission has discretion in how it administers statutory mandates by regulation.[34]

21. APPA's assertion that the Commission is "falling short" of meeting Congress's intent is without merit. In the proposed regulations, the Commission complies with each provision in section 215A(d)(2) with regard to designating and handling Critical Electric Infrastructure Information. The fact that those rules also apply to Critical Energy Infrastructure Information does not diminish the Commission's compliance under the

[32] 18 CFR 388.113(c)(1)(i)).

[33] NOPR, 155 FERC ¶ 61,278 at P 14.

[34] *See Anna Jacques Hosp. v. Burwell*, 797 F.3d 1155, 1165 (D.C. Cir. 2015) (holding that "interstitial question[s] of implementation" are left to the discretion of the implementing agency).

FAST Act. Rather, in this regard, the Commission's determination meets Congress's intent. Moreover, APPA's argument that "information related to cyber threats and defensive measures should not be 'protected' under a designation regime that also provides for potentially involuntary access by any federal employee . . ., landowners [or]any person who is a participant in a Commission proceeding . . ." and others has no basis in the text of the FAST Act. APPA notably cites to nothing in the FAST Act to support that argument.[35] On the contrary, Congress explicitly directed the Commission to include voluntary sharing in the regulations that the Commission is required to promulgate under the FAST Act.[36] Further, the implication of APPA's argument – that cyber information is different from other types of infrastructure information and therefore warrants different rules – fails to take into consideration that the Commission will evaluate each request for CEII, and each decision to voluntarily share CEII, on a case-by-case basis. For example, a person seeking cyber threat information would have to show a different need for the information than a person seeking information for a pipeline facility for a certificate proceeding.

[35] *See* APPA Comments at 15.

[36] Section 215A(d)(2)(D) states that the Commission "shall promulgate such regulations as necessary to … facilitate voluntary sharing of critical electric infrastructure information…" FAST Act, Pub. L. No. 114-94, section 61,003, 129 Stat. 1312, 1776.

22. The Commission agrees with TAPS and APPA that the Commission's regulations should incorporate the provision in section 215A(d)(1)(B) that CEII "shall not be made available by any Federal, State, political subdivision or tribal authority pursuant to any Federal, State, political subdivision or tribal law requiring public disclosure of information or records."[37] As to TAPS's and APPA's request that the Commission define the term "political subdivision," in section 215A(d)(1)(B) of the FAST Act to be consistent with the definition of that term in FPA section 201(f), Congress did not adopt the definition of "political subdivision" in section 201(f) for the purposes of the FAST Act. However, the Commission believes that the broad language of section 215A(d)(1)(B), as it applies to "any Federal, State, political subdivision or tribal authority," should encompass the instrumentalities and components of States. Section 215A(d)(1)(B) was included to protect CEII from mandatory disclosure. It

[37] APPA states that there may be instances where an entity could provide CEII to NERC who, in turn, may submit that entity's information to the Commission or DOE as CEII without notifying the entity. Thus, APPA is concerned the entity may not be aware that the information has been submitted to the Commission and designated as CEII. As a result, APPA suggests that the Commission establish notification procedures so that entities are aware that their information was designated as CEII. APPA Comments at 21-22. We see no need to adopt such a notification process. Section 1505 of NERC's Rules of Procedure already requires NERC, unless otherwise directed by the Commission or its staff, to notify submitting entities of requests made by the Commission to NERC for the submitting entities' information.

would be illogical to provide such protection to States, but not their instrumentalities and components.

23. The Commission disagrees with TAPS that the Commission should delete from the definition of Critical Energy Infrastructure Information the provision that states that Critical Energy Infrastructure Information "[i]s exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552."[38] As we have discussed above, Congress incorporated Critical Energy Infrastructure Information within section 215A's definition of Critical Electric Infrastructure Information without revision.[39] Accordingly, the Commission will retain its current definition of Critical Energy Infrastructure Information.

24. In response to the Trade Associations' comments seeking clarification if a name or location of a facility should be protected as CEII, the Commission's current practice is that information that "simply give[s] the general location of the critical infrastructure" or simply provides the name of the facility is not CEII.[40] However, under certain circumstances, information regarding the location of infrastructure or its name that is not

[38] 18 CFR 388.113(c)(2)(iii).

[39] *See Stone v. INS*, 514 U.S. 386, 397 (1995) (holding that "[w]hen Congress acts to amend a statute, we presume it intends its amendment to have real and substantial effect").

[40] 18 CFR 388.113(c)(1)(iv).

already publicly known could be CEII.[41] Therefore, we clarify that, while as a general matter the location or name of infrastructure is not CEII, a submitter of information to the Commission may ask that non-public information about the location, or the name, of critical infrastructure be treated as CEII. The submitter would have to provide a justification for the request and explain why the information is not already publicly known.

25. In response to NRECA's request that the Commission clarify that material treated as Critical Energy Infrastructure Information under the Commission's current regulations would, in most circumstances, be treated as CEII under the amended regulations, we note that such information should continue to qualify as CEII. We also note, however, in response to Powerex's comment, that it is conceivable that Critical Electric Infrastructure Information may include information that would not fall within the existing definition of Critical Energy Infrastructure Information.[42]

26. We agree with Powerex's comment that the Final Rule should only address CEII and not other types of information. In response to Powerex's concerns about a party's

[41] For example, the location of an operating transformer is likely publicly known. However, the location of a spare transformer housed in a central location may not be publicly known and, therefore, may qualify as CEII.

[42] For example, while Critical Energy Infrastructure Information must satisfy the four-part definition in amended section 388.113(c)(1), Critical Electric Infrastructure Information must meet the definition in amended section 388.113(c)(2).

due process rights, under the amended CEII regulations the Commission will balance the need to protect critical information with the potential need of parties participating in Commission proceedings to access CEII. For example, the Commission's regulations include a process for parties to access information directly from other parties in a Commission proceeding.[43]

27. In response to comments from TAPS, APPA, and the Trade Associations, the Commission agrees that the CEII NDA should reference the provision in section 215A(d)(1) that CEII is exempt from disclosure under any Federal, State, political subdivision or tribal law requiring public disclosure. We disagree that the State Agency NDA should be eliminated because it reinforces the minimum protections applicable to CEII that the Commission may provide to states as well as provides for additional protections beyond the exemptions in State public disclosure laws.[44]

28. Finally, the Commission declines to adopt the revision suggested by the Trade Associations to expressly state that the CEII regulations are not intended to supersede other laws, regulations, and agency rules that separately safeguard such data.[45] This Final Rule and adopted CEII amendments do not purport to supersede any other legal

[43] *See* 18 CFR 388.112(b)(2) and 388.113(g)(4).

[44] *See supra* note 27.

[45] *See* Trade Associations Comments at 26.

authorities other than the regulations and associated materials specifically amended in this Final Rule.

B. Criteria and Procedures for Determining What Constitutes CEII

1. General Criteria and Procedures

NOPR

29. Section 215A(d)(2)(A) requires the Commission to "establish criteria and procedures to designate information as critical electric infrastructure information." In the NOPR, the Commission proposed criteria and procedures for the handling of CEII consistent with section 215A(d)(2)(A).[46]

Comments

30. Commenters request that the Commission provide more detail on what qualifies as CEII.[47] The Public Interest Organizations, for example, ask the Commission to publish guidelines and criteria for designating information as CEII.[48] The Public Interest Organizations further recommend that the Commission publish "data tables that provide suggested classifications for common data types."[49] HRC asks that the Commission

[46] NOPR, 155 FERC ¶ 61,278 at P 16.

[47] Peak Comments at 8-10; Powerex Comments at 12; APS Comments at 5; APPA Comments at 17; WIRAB Comments at 5.

[48] Public Interest Organizations Comments at 4.

[49] *Id.* at 5.

require entities filing CEII to include a public cover letter providing a description of the facility the information relates to and describing the nature of the submission. HRC also contends that information submitted as CEII should include a more detailed description in eLibrary.[50] HRC contends that this information will better allow the public to understand the basis for the CEII classification.[51] HRC also requests that the Commission develop a procedure whereby the public can request that the Commission review information at the time of submission to ensure that it was properly submitted as CEII.[52] HRC contends that filing a CEII or FOIA request as a means of triggering the review of CEII classification is burdensome.[53]

31. WIRAB and APS commented that additional designation guidance is needed in order to avoid submitters' over-designation of documents as CEII. Specifically, WIRAB and APS recommend that the Commission establish separate criteria for determining when information qualifies as CEII on the basis of national security, economic security or public health or safety.[54]

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[50] HRC Comments at 2-3.

[51] *Id*. at 2.

[52] *Id.* at 3.

[53] *Id*.

[54] WIRAB Comments at 5; APS Comments at 5.

32. The Trade Associations maintain that the Commission's regulations should explicitly designate as CEII information "related to compliance with the Reliability Standards as critical electric infrastructure information and exempt it from disclosure under 388.113(f)."[55] The Trade Associations assert that a blanket presumption that information regarding Reliability Standards compliance is CEII is necessary because it "may … be difficult for a submitter to present, *ex ante*, a clear justification for meeting the critical electric infrastructure information definition for a particular system or asset, especially if the potential for negative effect could also arise from the disclosure of a combination of sets of information that alone may not meet the CEII definition."[56]

33. APPA and the Trade Associations raise concerns about how the designation criteria will apply to DOE.[57] Specifically, they assert that the Commission failed to provide criteria and procedures that would apply to DOE.[58] Additionally, Peak, Public Interest Organizations, and APPA request that the Commission hold a technical

[55] Trade Associations Comments at 12.

[56] *Id.* at 11.

[57] APPA Comments at 24-25; Trade Associations Comments at 23.

[58] *Id.*

conference on the implementation of the new CEII rules as part of the "consultation with the Secretary" required by FPA section 215A(d)(2).[59]

34. Finally, NRC requests that the Commission establish a generic CEII designation that other federal agencies can use to designate information.[60] NRC also recommends that the Commission clarify in the Final Rule that other federal agencies "are to establish their own procedures for identifying CEII on an information-specific basis utilizing the FERC's generic CEII standard."[61]

Commission Determination

35. The Commission is not persuaded that more detailed guidance or additional designation criteria in the CEII regulations are necessary. FPA section 215A(a)(2) defines Critical Electric Infrastructure as "a system or asset of the bulk-power system, whether physical or virtual, the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters." FPA section 215A(a)(3) includes Critical Energy Infrastructure Information within CEII. We believe that the regulations, as proposed, provide adequate

[59] Peak Comments at 6-7; Public Interest Organizations Comments at 5; APPA Comments at 25. WIRAB also requests a technical conference to discuss implementation of the FAST Act. WIRAB Comments at 11.

[60] NRC Comments at 1-2.

[61] *Id.* at 2.

guidance for a submitter or Commission staff to determine whether information is CEII and for the CEII Coordinator to make a determination. In addition, the criteria and designation procedures adopted herein are informed by the Commission's experience of implementing and administering the Critical Energy Infrastructure Information regulations over the past fifteen years.

36. The Commission does not agree that the scope of CEII should be modified, as suggested by the Trade Associations, to encompass information "related to compliance with the Reliability Standards." The Trade Associations' proposal is unduly broad and inconsistent with the FAST Act because it could lead to all infrastructure information, whether critical or not, being treated as CEII. For the same reason, we do not agree that the blanket presumption that information relating to compliance with Reliability Standards is CEII, proposed by the Trade Associations, is appropriate. Like other forms of CEII, however, information on compliance with Reliability Standards may be treated as CEII if the submitter justifies its treatment as CEII under the Commission's regulations.

37. In response to HRC's comments that documents listed as CEII could be better described in eLibrary, the level of detail needed for a document description in eLibrary is better addressed in our submission guidelines rather than in our regulations.[62]

38. In response to HRC's request for an additional process to obtain a ruling on CEII when it is filed, we believe that such a process is unnecessary, as entities seeking access to information filed as CEII may submit a FOIA or CEII request at any time, including promptly after that information is filed with the Commission. We further conclude that the proposed procedures are adequate for the Commission to process information submitted to the Commission, or generated by the Commission, as CEII.[63] As previously noted, the Commission receives over 7,000 CEII submissions a year; reviewing the information at the time of submission, in the absence of a specific request for that information, would be overly burdensome on the Commission's resources. In response to a CEII request, the CEII Coordinator will review the information to determine whether to designate it as CEII. Further, proposed section 388.113(d)(1)(iv) specifically states that the Commission retains the right to make determinations with regard to any claim of CEII status, at any time.

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[62] *See* CEII Filing Guide, https://www.ferc.gov/resources/guides/filing-guide/file-ceii/ceii-guidelines.asp. The Commission will update the CEII Filing Guide when the proposed regulations become effective.

[63] *See* amended sections 388.113(c) and (d).

39. In response to the comments from APPA and the Trade Associations, the Commission declines to revise the regulations to identify specific designation criteria and CEII procedures for DOE. Section 215A(d)(3) of the FAST Act provides that information "may be designated" by the Commission and DOE pursuant to the criteria and procedures that the Commission establishes.[64] The FAST Act, however, does not compel DOE to make any changes to its regulations in this regard, and as noted in the NOPR, nothing within the Commission's regulations would limit DOE's ability to designate CEII in accordance with the FAST Act.[65] Furthermore, we do not believe a technical conference is necessary to satisfy the requirement for consultation with DOE in the FAST Act.

40. Although the Commission recognizes that other agencies have an obligation to protect certain information in their custody, the FAST Act does not grant other federal agencies the authority to designate information as CEII. Critical Electric Infrastructure Information is specifically defined as information "designated as critical electric infrastructure information by the Commission or the Secretary of the Department of Energy pursuant to subsection (d)."[66] Congress's intent to limit the designation authority

[64] FAST Act, Pub. L. No. 114-94, section 61,003, 129 Stat. 1312, 1776.

[65] NOPR, 155 FERC ¶ 61,278 at P 16 n.12.

[66] FAST Act, Pub. L. No. 114-94, section 61,003, 129 Stat. 1312, 1776.

to the Commission and DOE is reinforced by the fact that only the staff of the Commission and DOE are subject to sanctions for unauthorized release under section 215A(d)(2)(C).[67] However, because NRC has raised valid concerns about the protection of sensitive information of the electric grid in its custody, the Commission will make the following change to the amended scope of section 388.113:

> Nothing in this section limits the ability of any other Federal agency to take all necessary steps to protect information within its custody or control that is necessary to ensure the safety and security of the electric grid. To the extent necessary, such agency may consult with the CEII Coordinator regarding the treatment or designation of such information.

41. By this change, the Commission does not limit the discretion of other federal agencies to protect sensitive information in their custody but provides a mechanism for agencies to consult with the Commission's CEII Coordinator regarding the treatment or designation of such information as CEII.[68] We believe this change strikes a reasonable balance by recognizing other federal agencies' discretion to protect their information, while adhering to the statutory framework that limits CEII designation authority to the Commission and DOE.

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[67] *Id.*

[68] For example, the Commission could establish the parameters of the Commission's role with regard to CEII with another federal agency through a Memorandum of Understanding with that agency.

2. Designation of Submissions to the Commission

NOPR

42. The Commission proposed to treat information submitted with a justification for CEII treatment as CEII, unless the submitter is otherwise notified by the Commission.[69]

Comments

43. APS asks that the Commission "deem" information as CEII at the time an entity submits the information to the Commission.[70] HRC and Tacoma Power are concerned that "treating" a submission as CEII is not a designation and, as a result, submitting entities may not be able to assert the FOIA exemption when faced with a records request unless and until the Commission makes a CEII designation determination.[71] Tacoma Power further requests that the Commission develop a process for state entities to receive a CEII designation determination so that state entities may assert any FOIA exemption with certainty.[72]

44. INGAA, NERC, and the Trade Associations request that the Commission change the comment period afforded to submitters of CEII to respond to a request for CEII from

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[69] NOPR, 155 FERC ¶ 61,278 at P 19.

[70] APS Comments at 6.

[71] HRC Comments at 2; Tacoma Power Comments at 4.

[72] Tacoma Power Comments at 4.

five calendar days to five business days, ten working days, or at least 30 calendar days, respectively.[73] APS and CEA comment that if the Commission determines that particular information is not CEII, the Commission should provide the submitter with an explanation of why the information does not meet the criteria for designation as CEII.[74] The Trade Associations also request that the Commission provide a more detailed explanation in instances when CEII is released over an objection from the submitter of the material.[75]

45. MISO, Trade Associations, CEA, and HRC submitted comments recommending changes to the Commission's processing and evaluation of justification statements that must accompany a submitter's request for CEII treatment. MISO is concerned that the Commission may automatically make information public if the submission fails to meet the Commission's regulations. Thus, MISO recommends that amended section 388.113(d)(1) be revised to make clear that failure to provide the justification or other required information will be considered in the determination of whether the information

[73] INGAA Comments at 4; NERC Comments at 15; Trade Associations Comments at 19.

[74] APS Comments at 6; CEA Comments at 6-7.

[75] Trade Associations Comments at 19-20.

will be maintained as CEII by the Commission, but it will not result in automatic disclosure of the information.[76]

46. The Trade Associations maintain information submitted to the Commission for designation as CEII that ultimately is determined not to be CEII should not automatically be disclosed to the public because such information may be subject to other laws and regulations restricting disclosure of the information.[77]

47. CEA recommends that the Commission provide the submitter with an opportunity to retract a submission and re-submit it with the appropriate justification.[78]

Commission Determination

48. As an initial matter, we correct the statement in the NOPR erroneously stating that under our current practice, "the Commission deems the designation on a submission accepted as submitted."[79] Our current practice is to *treat* information as CEII, and maintain it in our non-public files, when it is submitted with a request for CEII treatment. That practice is reflected in the current and proposed regulations.[80] Under the regulations

[76] MISO Comments at 7.

[77] Trade Associations Comments at 25-26.

[78] CEA Comments at 6-7.

[79] NOPR, 155 FERC ¶ 61,278 at P 19.

[80] *See* amended section 388.113(d)(1)(vi).

adopted in this Final Rule information that is submitted will not be *designated* CEII until the CEII Coordinator makes such a determination.

49. As to the comments submitted by Tacoma Power, the Commission is not persuaded that a special expedited process for designations in the event a State entity is facing a public records request is needed, because State and local entities may consult with the CEII Coordinator as to whether information that is subject to a State, local, or other type of records request is CEII under the Commission's regulations.[81]

50. In response to the comments from APS and CEA about the procedures for informing a submitter of a potential release or re-designation of CEII, the Commission's current practices are sufficient to comply with the FAST Act and we maintain those practices under the adopted regulations. The current practice is to provide notice to the submitter if a proposed CEII designation will be rejected or if CEII will be released over an objection. The notification will include an explanation as to why the information does not meet the criteria and the submitter will have an opportunity to comment or seek appropriate relief under amended section 388.113(e)(4).

[81] Section 215A(d)(1)(B) states that Critical Electric Infrastructure Information "shall not be made available by any Federal, State, political subdivision or tribal authority pursuant to any Federal, State, political subdivision or tribal law requiring public disclosure of information or records." FAST Act, Pub. L. No. 114-94, section 61,003, 129 Stat. 1312, 1776.

51. The Commission is not persuaded that it is necessary to make the changes proposed by MISO and CEA regarding treatment of information that is filed in a manner that does not meet our regulations. The amended regulations do not mandate automatic disclosure of the information. Furthermore, even if the Commission were to make information public, the Commission will provide notice to the submitter prior to any determination.[82]

52. The Commission adopts INGAA's proposal to change the comment period from five calendar days to five business days, and will change all references in section 388.113 from "calendar" days to "business" days. Allowing more time is not warranted because the issue of whether to release CEII is relatively limited and, as a general matter, the Commission endeavors to respond to requests for CEII as soon as possible. In addition, the Commission notes that submitters can request an extension of that time-period to submit comments to the Commission.

3. Information Included in NERC Databases

NOPR

53. The Commission proposed that information downloaded by Commission staff from private databases that are accessed pursuant to Commission order or regulation will be maintained as non-public information consistent with the Commission's internal

[82] *See* amended sections 388.113(d)(1)(iv) and 388.113(e)(3)-(4).

controls.[83] The Commission noted that in response to an information request, it will evaluate whether the information is CEII, proprietary information, or otherwise privileged or non-public and will provide the owner of the database or information (as appropriate) with an opportunity to comment on the request.[84]

Comments

54. Most commenters support treating data downloaded from the NERC databases as non-public. NERC agrees with the proposal to treat information downloaded from its databases as non-public, but it seeks clarification as to whether the Commission intends to designate the information as privileged and CEII.[85] TAPS requests that if the Commission determines to release database information, the manager of the database and the entity whose data would be released should receive notice and an opportunity to comment.[86]

55. The Trade Associations recommend that the Commission treat the NERC databases information that Commission staff does not download as inextricably

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[83] NOPR, 155 FERC ¶ 61,278 at P 17 n.13(citing *Availability of Certain North American Electric Reliability Corporation Databases to the Commission*, Order No. 824, 155 FERC ¶ 61,275 (2016)).

[84] *Id.*

[85] NERC Comments at 19.

[86] TAPS Comments at 5-7.

intertwined with downloaded information and thereby treat all of the information on each database as CEII.[87] TAPS raises concerns that information that is contained in a database may not be adequately protected from disclosure, because the data "is not being submitted to the Commission, but rather accessed by the Commission."[88]

CEA requests that the Commission respect Canadian information that may be accessed through any private databases accessible to the Commission.[89] CEA further comments that the Commission's information gathering through other databases be restricted to U.S. facility information only.[90]

Commission Determination

56. The Commission adopts the NOPR proposal to treat information *downloaded* from NERC databases as non-public[91] and to evaluate whether it should be designated as CEII in response to a request for the information or if the Commission determines such

[87] Trade Associations Comments at 15.

[88] TAPS Comments at 6.

[89] CEA Comments at 4.

[90] *Id.*

[91] This is consistent with the statement in Order No. 824 that the Commission "will take appropriate steps, as provided for in our governing statutes and regulations, in handling such information." Order No. 824, 152 FERC ¶ 61,208 at P 22.

information should be disclosed.[92] In addition, because the CEII designation only applies to information that is submitted to or generated by the Commission, information that Commission staff accesses and reviews, but never takes custody of, cannot be designated as CEII. Therefore, the Commission disagrees with the proposal to treat all of the information in an accessed database as inextricably intertwined CEII.[93]

57. The Commission clarifies that information downloaded by the Commission or its staff from a non-public NERC database will be treated as non-public information and will be afforded the same treatment as CEII. Thus, in the event the Commission receives a request for the information or the Commission determines such information should be disclosed, the Commission will "provide the owner of the database or information (as appropriate) with an opportunity to comment on the request."[94] In response to TAPS's comments, we clarify that, where practicable, we will notify the database owner and the information owner.[95]

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[92] The discussion above and our determination address the Trade Associations' request for clarification of Order No. 824 in Docket No. RM15-25-001.

[93] By the same token, information that is not downloaded cannot be disclosed under a FOIA request as the Commission would not possess the information.

[94] NOPR, 155 FERC ¶ 61,278 at P 17 n.13.

[95] We note that section 1505 of NERC's Rules of Procedure requires NERC, unless otherwise directed by the Commission or its staff, to provide notice to submitting entities in response to requests for the submitting entities' information by the Commission.

58. Finally, as to CEA's comment regarding Canadian information on other databases, we believe that CEA's request goes beyond the scope of this rulemaking proceeding, which is limited to amending the Commission's regulations regarding CEII.[96]

4. Designation of Commission-Generated Information

NOPR

59. For Commission-generated information, the NOPR explained that the CEII Coordinator, after consultation with the appropriate Commission Office Director, will determine whether the information meets the definition of CEII.[97] The CEII Coordinator will then determine how long the CEII designation should last and, as appropriate, whether to make any re-designation.[98]

Comments

60. The Trade Associations request that the Commission establish a process in which appropriate stakeholders may participate in the Commission's CEII designation

[96] The Commission has addressed the scope of information covered by specific data collection requirements in individual proceedings. For example, in Order No. 824, concerning Commission access to certain NERC databases that include data about both U.S. and Canadian facilities, the Commission revised its regulations to indicate that "Commission access will be limited to data regarding U.S. facilities." Order No. 824, 155 FERC ¶ 61,275 at P 38.

[97] NOPR, 155 FERC ¶ 61,278 at P 21.

[98] *Id.*

determinations for Commission-generated information.[99] The Trade Associations assert that whether the information is submitted to the Commission or not, "owners and operators of that critical infrastructure who will be faced with defending such a potential attack deserve to have input into the determination of whether or not such information should be disclosed."[100]

Commission Determination

61. The Commission determines that there is no need for stakeholder participation in the designation of Commission-generated information. The Commission has the expertise and experience to make determinations about whether Commission-generated information is CEII. And as a practical matter, it would not be appropriate in some circumstances for stakeholders to be privy to Commission-generated information that qualifies as CEII. For example, Commission-generated CEII may contain information that is otherwise non-public or privileged. To the extent that an entity believes that a Commission-generated document contains CEII about its facility, the entity is not precluded from raising that concern with the CEII Coordinator.

[99] Trade Associations Comments at 24.

[100] *Id.*

5. Segregable Information

NOPR

62. The NOPR recognized that information submitted to the Commission may contain parts that are CEII and parts that may not be CEII. As a result, the NOPR proposed to require entities submitting CEII and Commission staff who generate CEII, to the extent feasible, to segregate the CEII (or information that reasonably could be expected to lead to the disclosure of the CEII) from non-CEII at the time of submission or staff's generation, respectively.[101]

Comments

63. HRC and Powerex support the requirement to segregate CEII from non-CEII and encourage efforts to prevent the over-classification of information.[102] TAPS asks the Commission to confirm that submitting a redacted public version of a filing satisfies the requirement to segregate CEII.[103] Powerex asks the Commission to clarify that derivative analyses performed by governmental entities or their contractors that use or rely on CEII,

[101] NOPR, 155 FERC ¶ 61,278 at P 22.

[102] HRC Comments at 3; Powerex Comments at 16-17.

[103] TAPS Comments at 14.

without more detail, should not be designated as CEII solely based on the fact the analysis relies on or uses CEII.[104]

Commission Determination

64. The Commission clarifies that submitting a properly redacted public version of information submitted as CEII meets the requirement established in section 215A(d)(8). Moreover, derivative analyses that use or rely on CEII, without actually containing or disclosing CEII, do not automatically qualify as CEII unless the information provided could reasonably be expected to lead to the disclosure of CEII.

6. Duration of Designation

NOPR

65. Section 215A(d)(9) provides that information "may not be designated as critical electric infrastructure information for longer than 5 years, unless specifically re-designated by the Commission or the Secretary, as appropriate."[105] The NOPR stated that the five-year designation period will commence upon submission, and the expiration of the five-year period will not automatically trigger the public release of the information unless the Commission determines it is appropriate to do so.[106] The NOPR also stated

[104] Powerex Comments at 16.

[105] FAST Act, Pub. L. No. 114-94, section 61,003, 129 Stat. 1312, 1776.

[106] NOPR, 155 FERC ¶ 61,278 at P 18 n.14 and P 24.

that the Commission will make a re-designation determination when an entity requests the information; when staff determines a need to remove the designation; or when a submitter requests that the information no longer be treated as CEII.[107] Consistent with current practice, the NOPR proposed that a NDA will require protection of CEII past the expiration of the CEII designation marked on the information and that the recipient of CEII from the Commission must receive prior authorization from the Commission before making any disclosure.[108]

66. In the NOPR, the Commission proposed removing the CEII designation when the information no longer could impair the security or reliability of not only the bulk-power system or distribution facilities but also other forms of energy infrastructure.[109] The Commission stated that the Commission would provide notice to the submitter "in the instance where the Commission takes the affirmative step to rescind the designation."[110]

[107] *Id.*

[108] *Id.* P 26.

[109] *Id.* P 27.

[110] *Id.*

Comments

67. Several commenters support the proposal to maintain information as non-public after CEII designations marked on the information expire.[111] However, Peak requests that the Commission determine at the time of the designation whether the data will lose its protection after the five-year term ends and recommends creating designation categories that include designation timeframes.[112] The Trade Associations and APPA ask the Commission to automatically re-designate information, absent objection.[113] Tallgrass requests that a designation remain for the life of a pipeline facility.[114] INGAA requests that the Commission never un-designate CEII related to pipeline facilities on its own initiative or unilaterally as long as the facility is in operation.[115]

68. APS requests clarification on whether the criteria for re-designating CEII are the same as the criteria used for the initial CEII designation.[116]

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[111] *See, e.g.*, ITC Comments at 2-3; INGAA Comments at 3; NRECA Comments at 9.

[112] Peak Comments at 10-11 (recommending categories such as "transmission and generation outage data, generator-specific forecast data, transmission facility and load status and measurements, specific facility modeling data, and device lists").

[113] Trade Associations Comments at 21-22; APPA Comments at 20.

[114] Tallgrass Comments at 3.

[115] INGAA Comments at 3.

[116] APS Comments at 12.

69. NRECA and ITC assert that the NOPR is unclear with respect to the notice and comment provisions pertaining to a determination to remove CEII designations. In particular, they urge the Commission to clarify that submitters will receive notice, an opportunity to comment, and appeals rights prior to any determination to remove a CEII designation and prior to any disclosure of the information.[117] ITC also states that the NOPR proposal to "notify the person who submitted the document and give the person an opportunity (at least five calendar days) in which to comment in writing prior to the removal of the designation" is insufficient notice. ITC asks the Commission to provide notice and an opportunity to comment not only to the "person who submitted the document" but also to the organization on whose behalf the person submitted the document.[118]

70. APPA requests that the Commission revise the language in amended section 388.113(e) to ensure that designations made by DOE cannot be removed by the Commission.[119]

[117] NRECA Comments at 11; ITC Comments at 3-4.

[118] ITC Comments at 3.

[119] APPA Comments at 26.

Commission Determination

71. The Commission adopts the NOPR proposal to treat expired CEII as non-public until a re-designation determination is made. Such a process is supported by the majority of commenters and is reasonable given the large volume of CEII presently in the Commission's files and anticipated to be filed. Consistent with the NOPR's intent, the Commission will modify the regulatory language in amended section 388.113(e) to indicate that the Commission will treat information as non-public after the CEII designation has lapsed; that no information will be released as non-CEII unless the Commission decides to release the information; and that notice and opportunity for comment will be provided to the submitter prior to any determination that the CEII designation of a submitted document should be removed.

72. We do not adopt the recommendations to automatically re-designate information, designate by category, or designate for the lifetime of a facility. Blanket designations are inconsistent with FPA section 215A(d)(9), which requires the Commission to specifically re-designate information.[120]

[120] Section 215A(d)(9) states that information "may not be designated as critical electric infrastructure information for longer than 5 years, unless specifically re-designated by the Commission or the Secretary, as appropriate." FAST Act, Pub. L. No. 114-94, section 61,003, 129 Stat. 1312, 1776.

73. In response to ITC's comments that providing notice to the person who submitted the document is insufficient, we clarify that the Commission will provide the person and/or the organization identified on the submission notice an opportunity to comment as well as appeal rights prior to any determination to rescind a CEII designation or release the information.[121]

74. With respect to APPA's comments regarding the Commission's ability to remove a DOE designation, we clarify that the Commission does not intend to remove any designations that DOE may make. With respect to APS's request for clarification regarding re-designations, we clarify that the regulations adopted herein do not differentiate between the processes for designating or re-designating information as CEII.

7. Judicial Review of Designation

NOPR

75. The Commission proposed to require a person seeking to challenge a Commission designation determination to file an administrative appeal with the Commission's General Counsel prior to seeking judicial review in federal district court under section 215A(d)(11).[122]

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[121] The Commission will use the relevant service list, where appropriate, to determine the appropriate recipient.

[122] NOPR, 155 FERC ¶ 61,278 at P 28.

Comments

76. HRC contends that the Commission's administrative appeal requirement should not be mandatory.[123] NRECA asserts that the Commission does not have a legal basis for the administrative appeal requirement.[124] NRECA also recommends that the regulations specify the timeframes in which appeals can be pursued; a timeframe for when a decision on the appeal should be rendered; and that the designation will remain in place until legal challenges have been exhausted.[125]

77. NRECA contends that the Commission must revise the delegation authority provisions in section 375.313 to allow the General Counsel to hear and decide an administrative appeal.[126]

Commission Determination

78. With respect to NRECA and HRC's comment, Congress directed the Commission to establish criteria and procedures to designate information as CEII, and the mandatory appeal to the Commission's General Counsel is a procedure that will assist in proper designation of such information. Requiring a party to exhaust administrative remedies

[123] HRC Comments at 3.

[124] NRECA Comments at 11; HRC Comments at 3-4.

[125] *Id*.

[126] NRECA Comments at 12.

prior to taking a matter to court is a standard and basic function of administrative law.[127] The administrative appeal process gives the Commission an opportunity to correct any error and to ensure that Commission policy has been properly complied with. This process creates efficiency in the administrative process and promotes judicial economy. In addition, the current FOIA and CEII process provides for administrative appeal.[128]

79. In response to NRECA's suggestion regarding appeal timeframes, the Commission will revise the amended regulations at section 388.113(j) to provide more specificity about the process for submitting an administrative appeal. After receiving a determination that information no longer qualifies as CEII, a submitter may appeal that determination. To make an appeal, the submitter must file a notice of appeal to the General Counsel, copying the CEII Coordinator, within 5 business days of the date of the determination.[129] A statement in support of the appeal (a statement providing applicable facts and legal authority) must be submitted to the General Counsel within 20 business

[127] *See Hidalgo v. FBI*, 344 F.3d 1256, 1258-59 (D.C. Cir. 2003) (holding that "exhaustion of administrative remedies is generally required before filing suit in federal court so that the agency has an opportunity to exercise its discretion and expertise on the matter and to make a factual record to support its decision").

[128] NOPR, 155 FERC ¶ 61,278 at P 28.

[129] Requiring the submitter to inform the Commission of its intent to appeal within 5 business days will allow the Commission to know sooner than later whether the submitter plans to challenge the decision and, if not, allow the Commission to disclose the information sooner.

days of the date of the determination. The appeal will be considered received upon receipt of the statement in support of the appeal. A determination denying a request for disclosure or denying a request to designate a document as public may also be appealed. A notice of appeal is not required for these determinations because information would not be disclosed under the challenged decision. However, the requester must submit an appeal within 20 business days of the date of the determination by submitting its statement in support of its appeal to the Commission's General Counsel.[130] The General Counsel or the General Counsel's designee will make a determination with respect to any appeal within 20 business days after the receipt of the appeal, unless extended pursuant to section 388.110(b)(1), which will equally apply to CEII for purposes of appeals.

80. To avoid any uncertainty, the Commission will amend section 375.309 to include a provision to make clear that the Commission has delegated to the General Counsel authority to make determinations on behalf of the Commission on appeals of designations and determinations regarding CEII.

[130] The Trade Associations suggest that the Commission should issue an order on appeal of any denial of an information owner's objections to disclosure of CEII pursuant to a NDA. Trade Association Comments at 20. Under our current practice, the decision to disclose CEII pursuant to a NDA is appealable directly to a district court under 5 U.S.C. 552(a)(4)(B). There is no need to establish an additional procedure under the amended regulations that requires the Commission to issue an order on appeal.

C. Duty to Protect CEII

NOPR

81. The Commission proposed revisions to strengthen the handling requirements for Commission employees and external recipients of CEII. With respect to Commission staff, the Commission proposed to add section 388.113(h) to require Commissioners, Commission staff, and Commission contractors to comply with the Commission's internal controls.[131] For external recipients of CEII, the Commission proposed requiring requesters to provide specific information to demonstrate a legitimate need for the information and to include a signed statement attesting to the accuracy of the information provided in any CEII request.[132] The Commission also proposed that all NDAs minimally require that CEII: (1) will only be used for the purpose it was requested; (2) may only be discussed with authorized recipients; (3) must be kept in a secure place in a manner that would prevent unauthorized access; and (4) must be destroyed or

[131] NOPR, 155 FERC ¶ 61,278 at P 30.

[132] *Id.* PP 33-34. Specifically, the Commission proposed to require a requester to demonstrate: (1) the extent to which a particular function is dependent upon access to the information; (2) why the function cannot be achieved or performed without access to the information; (3) whether other information is available to the requester that could facilitate the same objective; (4) how long the information will be needed; (5) whether or not the information is needed to participate in a specific proceeding (with that proceeding identified); and (6) whether the information is needed expeditiously. *Id.*

returned to the Commission upon request. The Commission also proposed that the NDA make clear that the Commission may audit compliance with the NDA.

Comments

82. The Trade Associations request that the Commission provide further details of the content and nature of the internal controls and include them in the Commission's regulations.[133] MISO agrees that the Commission should have internal controls and notes that the internal controls should be enforced.[134]

83. Several commenters request that the Commission expand the list of minimum requirements for a NDA. MISO and NRECA note that the NOPR recognizes the need for requesters to protect CEII after the designation has lapsed and recommend that the duty to protect expired CEII be included in the minimum NDA requirements.[135] MISO, the Trade Associations and APS recommend that the Commission require recipients to report all unauthorized disclosures.[136] NERC recommends adding to the NDA a requirement

[133] Trade Associations Comments at P 36-37. The Trade Associations also state that the Commission should consider expounding on recommendations from the DOE IG.

[134] MISO Comments at 8.

[135] MISO Comments at 8; NRECA Comments at 10.

[136] MISO Comments at 9; Trade Associations Comments at 26; APS Comments at 10.

that a recipient must destroy or return CEII by specific deadlines.[137] NERC and the Trade Associations request that submitters be able to enforce the terms of a NDA that covers the submitter's CEII.[138]

84. In addition to the NDA recommendations stated above, the Trade Associations request that the Commission add the following clauses to the NDA: (1) recipients of CEII shall have information protection policies and procedures to protect the CEII; and (2) an officer of the recipient's organization, on behalf of the organization, as well as all individuals who will have access to the CEII, shall execute the NDA, which shall specify that the individuals and organization face sanctions for failure to honor the terms of the NDA.[139]

85. APS encourages the Commission to review the current NDA for potential gaps, such as the lack of an obligation to treat CEII with the same degree of care as a requester would treat its own confidential or proprietary information.[140] NRECA asks the

[137] NERC Comments at 14.

[138] NERC Comments at 14; Trade Associations Comments at 26.

[139] Trade Associations Comments at 26.

[140] APS Comments at 9-10.

Commission to clarify that a NDA is required when an entity receives CEII after the designation expires.[141]

86. Peak seeks clarification regarding the requirements for keeping CEII in a secure place and manner.[142] Peak explains that recipients of CEII may have different views of what constitutes a "secure place."[143]

87. The Trade Associations recommend that the Commission adopt a monitoring and enforcement process to discourage unauthorized disclosures and ask for additional language clarifying that "any person or entity found to have used or disclosed CEII in a manner inconsistent with the NDA will lose its access to CEII for an extended period of time."[144] The Trade Associations and NRECA suggest that the Commission determine that noncompliance with the NDA would subject an individual to penalties of up to $1 million per violation per day.[145]

88. NERC requests that the Commission ensure that requesters have not been convicted of criminal activity by performing background checks, reviewing watch lists,

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[141] NRECA Comments at 10.

[142] Peak Comments at 14-15.

[143] *Id*.

[144] Trade Associations Comments at 34.

[145] Trade Associations Comments at 35; NRECA Comments at 16-17.

and verifying security clearances to prevent inadvertent disclosures of CEII to a person with a criminal record or who is under investigation or on a terrorist watch list.[146]

89. NERC also proposes that the Commission include evidentiary criteria to determine whether a requester of CEII is legitimate, and the Trade Associations ask the Commission to conduct risk assessments on all requesters.[147]

90. APS urges the Commission to require all requests to include at least two business references and the submission of documentation of authority for organizational requesters.[148] Peak requests that if a CEII request is not for participation in a specific proceeding, the requester should be required to include in its statement of need a "reliability or societal benefit."[149]

Commission Determination

91. We disagree with the Trade Associations' recommendation that we provide additional details regarding internal controls and that we include internal controls in the Commission's regulations. The NOPR stated that the internal controls will address "how

[146] NERC Comments at 13-14.

[147] NERC Comments at 12-14; Trade Associations Comments at 33.

[148] APS Comments at 7-8.

[149] Peak Comments at 14.

sensitive information, including CEII, should be handled, marked, and kept."[150] We find that this statement provides sufficient details regarding the nature of the internal controls. We also conclude that internal controls should not be specified in the Commission's regulations to allow Commission staff the flexibility to revise such controls as needed.[151]

92. Amended section 388.113(h)(2) only includes "minimum" requirements for a NDA and is not intended to be exhaustive or preclude other requirements. Under certain circumstances the Commission may add additional provisions to the NDA and submitters may request that additional provisions be added to the NDA.

93. In response to MISO's and NRECA's comments, the Commission will amend section 388.113(h)(2) to require a recipient of CEII under a NDA to protect the CEII after a designation lapses as part of the list of minimum requirements of a NDA. In response to the comments by MISO, the Trade Associations and APS, we will also amend section 388.113(h)(2) to add an obligation to require CEII recipients to promptly report all unauthorized disclosures of CEII to the Commission.

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[150] NOPR, 155 FERC ¶ 61,278 at P 30.

[151] In developing this Final Rule and the internal controls, the Commission has been cognizant of the recommendations of the DOE Inspector General Report from January 30, 2015 as well as the Commission's earlier response thereto, which are a matter of public record. *See* Department of Energy, Office of Inspector General, Inspection Report, Review of Controls for Protecting Nonpublic Information at the Federal Energy Regulatory Commission, DOE/IG-0933 (January 2015), http://energy.gov/ig/downloads/inspection-report-doeig-0933.

94. In response to NRECA's concern, the Commission clarifies that a requester seeking information past the expiration of the CEII designation marked on the information must still pursue the information through the CEII or FOIA processes. We read NRECA's comments to apply to situations where an entity requests information that has been submitted to the Commission more than five years prior to the request and the Commission has not made a determination to re-designate the information. In these situations, the CEII Coordinator will make a re-designation determination as part of the response to a request seeking access to information that has a designation determination older than five years. If the information is re-designated as CEII, then it will be processed pursuant to the Commission's requirements for CEII.

95. The Commission is not persuaded by Peak's comments that there is a need to clarify what constitutes maintaining CEII in a secure place. We believe that a "secure place," as articulated in the NDA, has a well-understood meaning, *i.e.* safe or free from unauthorized access or a risk of loss.

96. The Commission believes that it has sufficient authority to enforce the terms of the NDA and, as a result, it is unnecessary to confer on NERC or others authority to enforce the terms of a NDA.

97. In response to the comments of the Trade Associations and NRECA, the Commission notes that the FAST Act does not require the Commission to develop sanctions for external recipients of CEII. In any event, the general CEII NDA already

states that a violation of the NDA may result in civil sanctions for an external recipient of CEII, and it will continue to do so. It is not necessary to list all the various civil sanctions that may apply, as each matter would be reviewed on its own facts. For these reasons, we also decline to adopt the Trade Associations' recommendation that we add to the minimum requirements of a NDA a provision that CEII recipients may be sanctioned by losing access to CEII for an extended period of time.

98. The Commission agrees that it is important to ensure that requesters of CEII do not pose security risks. CEII requesters have historically fallen into different categories, including individuals known to the Commission with no known risk.[152] The Commission will continue the practice of requiring information needed to verify the legitimacy of a requester on an as-needed basis. As such, there is no need for a CEII requester to demonstrate that there is a "reliability or social benefit" to the request. We believe that our procedures have adequately assessed whether requestors should receive CEII. In addition, we propose additional requirements for a requester to obtain CEII information. Thus, given these procedures, it is not necessary to mandate specific background check criteria in the regulations. Moreover, while the current request form asks for a business

[152] Requests are typically received from public utilities, gas pipelines, hydro developers, academics, landowners, public interest groups, researchers, renewable energy organizations, and consultants.

reference, we are not persuaded that such a submission is necessary in all instances or that two references are necessary.[153]

D. Sanctions

NOPR

99. Section 215A(d)(2)(C) of the FPA requires the Commission to "ensure there are appropriate sanctions in place for Commissioners, officers, employees, or agents of the Commission or DOE who knowingly and willfully disclose critical electric infrastructure information in a manner that is not authorized under this section."[154] The Commission proposed sanctioning unauthorized disclosures of CEII by Commission personnel and further noted that DOE will have responsibility for sanctions for unauthorized disclosures by its officers and employees.[155] The Commission also proposed to refer any misconduct by the Chairman or Commissioners to the DOE Inspector General (DOE IG).[156]

Comments

100. Several commenters, including APPA and the Trade Associations, point to the absence of stated sanctions for Commissioners in the NOPR and request that the

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[153] Electronic CEII Request Form, http://www.ferc.gov/resources/guides/filing-guide/ceii-request.asp.

[154] FAST Act, Pub. L. No. 114-94, section 61,003, 129 Stat. 1312, 1776.

[155] NOPR, 155 FERC ¶ 61,278 at P 36.

[156] *Id.*

Commission consider whether to impose civil sanctions under section 316A of the FPA and criminal penalties under section 316(b) of the FPA.[157] APPA also recommends that the Commission consider referring unauthorized CEII disclosures by Commissioners to the Department of Justice (DOJ) and that the Commission coordinate with DOE to outline a new or cite an existing procedure that DOE can utilize to sanction its employees.[158] MISO suggests that the Commission's General Counsel be tasked with referring any willful, unauthorized disclosures to the DOE IG.[159] NRECA asks that a mechanism be put in place for the public to make a referral to the DOE IG if they are aware of any misconduct.[160] MISO and NRECA recommend that the Commission revise

[157] *See* Trade Associations Comments at 40 (noting that CEII protections adopted in the FAST Act were adopted in the context of what many considered to be an inappropriate disclosure of CEII by a former FERC Commissioner); *see also* APPA Comments at 28. APPA states that the Commission has authority to impose civil penalties against "any person" who violates any provision of any Commission rule and may use criminal penalties under FPA section 316(b) for knowing and willful violations, by "any person" of Commission rules or regulations under the FPA.

[158] APPA Comments at 27, 29. APPA also asserts that a DOE employee sanctioned for unauthorized disclosure may be able to challenge their sanction "on grounds that it was not promulgated by the Commission, as directed by Congress."

[159] MISO Comments at 10.

[160] NRECA Comments at 16.

its proposed rule to make clear that the Commission "shall" refer any misconduct to the DOE IG and to allow the public to refer matters to the DOE IG.[161]

Commission Determination

101. As discussed below, we conclude that the sanctions adopted in this Final Rule, as well as other reforms adopted prior to the passage of the FAST Act, provide sufficient deterrents to the unauthorized disclosure of CEII.

102. First, we note that, in addition to the changes adopted in this Final Rule, the Commission has recently made a number of changes to its internal procedures to ensure the protection and security of CEII.

103. The Commission has revised its security classification and ethics training to ensure that Commission employees are aware of their responsibility to protect sensitive nonpublic information. The Commission also has strengthened its protection of CEII and other sensitive, non-public information. For example, the Commission conducted a comprehensive review of its internal information governance procedures, which informed the development of the internal controls referenced in this Final Rule. We believe that these reforms should help protect against unauthorized disclosure of CEII.

104. The Commission has also taken steps to ensure that there are appropriate sanctions in place for certain persons who knowingly and willfully disclose CEII without

[161] MISO Comments at 10; NRECA Comments at 16.

authorization. With respect to former employees and Commissioners, the Commission has strengthened certain requirements applicable to departing employees and Commissioners by requiring them to certify that they are not unlawfully removing records from the agency. This certification form also identifies and requires a departing employee or Commissioner to acknowledge the potential criminal penalties associated with the unlawful removal or destruction of federal records. While these changes pre-date the passage of the FAST Act, they are an important component of the Commission's ongoing efforts to protect against improper disclosure of CEII.

105. As to existing Commission officers, employees, and agents, we conclude that the sanctions adopted in this Final Rule are appropriate, as they provide for possible dismissal from federal service and criminal prosecution for improper disclosure of CEII. These sanctions should serve as a deterrent to, and punishment for, improper activity.

106. With respect to Commissioners, we believe it is appropriate that violations be referred to the DOE IG, as that office is equipped to investigate a Commissioner's actions and impose sanctions on a Commissioner through an independent process outside of the Commission's enforcement process.[162] For example, it is within the DOE IG's discretion after concluding its investigation to refer a matter to the DOJ for criminal prosecution

[162] We note that no commenter has indicated that the DOE IG has insufficient tools to investigate and, as appropriate, pursue sanctions for a Commissioner.

Upon becoming aware of a potentially improper disclosure of CEII, the Designated Agency Ethics Official (DAEO) will oversee an examination of those circumstances. If there is reason to believe that an improper disclosure has occurred, the DAEO will refer the matter to the DOE IG.

107. Finally we conclude that there is no need to add a mechanism to our regulations for the public to make a referral to the DOE IG, as the DOE IG has an existing hotline in place for the public.[163] The Commission will also continue to defer to DOE as to what sanctions would be appropriate for DOE officers and employees.

E. Voluntary Sharing of CEII

NOPR

108. Section 215A(d)(2)(D) of the FPA requires that the Commission:

> taking into account standards of the Electric Reliability Organization, facilitate voluntary sharing of critical electric infrastructure information with, between, and by — (i) Federal, State, political subdivision, and tribal authorities; (ii) the Electric Reliability Organization; (iii) regional entities; (iv) information sharing and analysis centers established pursuant to Presidential Decision Directive 63; (v) owners, operators, and users of critical electric infrastructure in the United States; and (vi) other entities determined appropriate by the Commission.[164]

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[163] *See* DOE IG Hotline, http://www.energy.gov/ig/services.

[164] FAST Act, Pub. L. No. 114-94, section 61,003, 129 Stat. 1312, 1776.

109. The Commission proposed that it would voluntarily share Commission-generated CEII and CEII submitted to the Commission with individuals or organizations when there is a need to ensure that energy infrastructure is protected.[165] Under this proposal, the Commission may voluntarily share CEII without receiving a request for the CEII.[166] However, the NOPR proposed that all voluntarily shared CEII would be shared subject to an appropriate NDA or Acknowledgement and Agreement.[167] Additionally, the NOPR proposed to require an Office Director or his designee to consult with the CEII Coordinator before voluntarily sharing CEII.[168]

110. In the NOPR, the Commission also noted that it retains the discretion to release information as necessary for other federal agencies to carry out their jurisdictional responsibilities.[169]

111. The NOPR also proposed that the Commission may impose additional restrictions on how voluntarily shared CEII may be used and maintained.[170] Where practicable, the

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[165] NOPR, 155 FERC ¶ 61,278 at PP 37-38, 40.

[166] *Id.* P 38.

[167] *Id.* P 40.

[168] *Id.* P 39.

[169] *Id.*

[170] *Id.* P 41.

Commission proposed providing notice of its voluntary sharing of CEII to the submitter of the CEII.[171]

Comments

112. Several commenters observe that the NOPR only addressed the Commission's voluntary sharing of CEII and did not establish guidelines for the voluntary sharing of CEII "with, between, and by" other entities.[172] Powerex requests that the Commission facilitate the sharing of CEII between and by owners, operators, and users of the critical electric infrastructure, while still adequately safeguarding CEII.[173] The Public Interest Organizations and WIRAB recommend that the Commission adopt a "white list" of CEII requesters that the Commission determines do not pose a risk of unauthorized disclosure.[174] They also contend that the Commission should adopt a universal NDA to encourage more sharing between and by non-Commission entities.[175] WIRAB also seeks

[171] *Id.* P 42. The Commission noted that it may not be practicable to provide notice to the submitter in instances where voluntary sharing is necessary to maintain infrastructure security, to address a potential threat, or in other exigent circumstances.

[172] *See, e.g.*, Peak Comments at 5-6; Powerex Comments at 13-14; APPA Comments at 31; NRECA Comments at 13.

[173] Powerex Comments at 13-15.

[174] Public Interest Organizations Comments at 8-9; WIRAB Comments at 9.

[175] *Id.*

standardization of NDAs used by NERC, regional entities, and the owners and operators of Critical Electric Infrastructure in the United States.[176]

113. The Joint RTOs (ISO New England, Inc. and Southwest Power Pool, Inc.) suggest that the Commission facilitate the sharing of CEII by permitting regional transmission organizations (RTOs), independent system operators (ISOs), and other entities with FERC-approved tariffs or similar agreements to share CEII "between the entities relying on their tariff information-handling commitments."[177] In response, PJM states that the Commission should reject the Joint RTOs' proposal, arguing that it is incomplete and overbroad and fails to acknowledge results achieved through the current sharing of CEII.[178] The Joint RTOs, in reply comments, state that their proposal would simply allow ISOs, RTOs, and other entities with Commission-approved tariffs that have planning and operations responsibilities to use those tariffs to facilitate information-sharing.[179]

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[176] WIRAB Comments at 10.

[177] Joint RTOs Comments at 4. MISO also suggests the Commission encourage sharing between planning authorities and transmission planners. *See* MISO Comments at 10.

[178] PJM Reply Comments at 2.

[179] Joint RTOs Reply Comments at 2.

114. NERC generally supports the Commission's proposal to facilitate voluntary information sharing with NERC, regional entities and information sharing and analysis centers. NERC, nonetheless, requests that the Commission, under appropriate circumstances, share CEII with the Electricity Information Sharing & Analysis Center (E-ISAC) when voluntarily sharing CEII with a governmental entity.[180] NERC asks that the voluntary sharing process include coordination between the CEII Coordinator and certain Commission office staff prior to any disclosure.[181]

115. APS, the Trade Associations and CEA ask for additional criteria as to how and when the Commission will voluntarily share information.[182]

116. APPA asserts that FPA § 215A(d)(2)(D) directs the Commission only to facilitate voluntary sharing of CEII among electricity subsector stakeholders – not to preemptively share CEII with interested parties.[183] APPA asserts that when the Commission voluntarily shares submitted information, it effectively forces the entity that submitted the information as CEII to share its information with others, which may reduce the incentive

[180] NERC Comments at 9.

[181] *Id.*

[182] APS Comments at 13; Trade Associations Comments at 27; CEA Comments at 5.

[183] APPA Comments at 30.

for the entity to voluntarily share CEII with the Commission.[184] APPA recommends that the Commission designate E-ISAC and any other appropriate Information Sharing and Analysis Organizations (ISAOs) as forums through which CEII can be shared under FPA § 215A, and to apply the liability protections of FPA section 215A(f)(3) to those entities.[185] APPA also recommends that the Commission provide protections like those that are utilized by other federal agencies to facilitate information sharing activity.[186]

117. The Trade Associations request that the regulations explicitly state that the voluntary sharing of CEII is limited to instances where the Commission has determined that there is a need to "ensure that energy infrastructure is protected."[187]

118. CEA requests that the Commission include language clarifying that the Commission will make every reasonable effort to provide advance notice before sharing CEII and will provide after-the-fact notice if prior notice is not practical.[188] MISO

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[184] *Id.*

[185] APPA Comments at 31-32.

[186] *Id.* at 31-32. For example, APPA proposes that the Commission allow for "source anonymizing" shared CEII or to adopt DHS's Traffic Light Protocol to ensure information is shared with the correct audience.

[187] Trade Associations Comments at 27-28.

[188] CEA Comments at 6. NRECA also references the need to provide notice as soon as possible, even if such notice is after the disclosure. *See* NRECA Comments at 12.

recommends that the Commission adopt regulatory language indicating that "when prior notice is not given, submitters of CEII shall receive notice of a limited release of CEII as soon as practicable."[189] NRECA requests that the Commission clarify that any disclosure by the Commission on the basis of "voluntary sharing" must be subject to the same notice, comment, and appeal rights provisions that are afforded to submitters in response to CEII requests.[190]

119. The Trade Associations state that the proposed regulations could be strengthened by: (1) limiting and defining the circumstances where notice would "not be practicable"; and (2) allowing the submitters an opportunity to provide comments protesting the release of information the Commission proposes to voluntarily share.[191]

120. Finally, TAPS requests that the Commission revise its delegations to reflect the NOPR's proposal that Office Directors will engage in voluntary sharing.[192]

Commission Determination

121. Many of the commenters misapprehend how CEII may be voluntarily shared under the FAST Act or otherwise seek to expand the Commission's CEII sharing

[189] MISO Comments at 11.

[190] NRECA Comments at 12-13.

[191] Trade Associations Comments at 30.

[192] TAPS Comments at 12-13.

program in ways that neither the FAST Act nor the NOPR contemplated. Under FPA section 215A(a)(3), CEII is limited to information that is submitted to, or generated by, the Commission and designated as such by the Commission (or information submitted to, or generated by DOE, and designated as such by DOE).[193] In voluntarily releasing CEII to a person, the Commission imposes obligations on that person through a NDA. However, the Commission's CEII rules do not, and are not intended to, address information that an entity has unilaterally determined to be CEII and never submitted to the Commission.[194] In addition, the Commission's regulations do not cover an entity that has submitted CEII to the Commission but intends to share the same information with others outside of the Commission's processes. To be clear, an entity that receives CEII from the Commission is subject to the restrictions in the applicable NDA, including restrictions on use and disclosure. However, an entity that submitted the information to the Commission is not subject to a NDA and, as a result, the Commission's rules do not

[193] FAST Act, Pub. L. No. 114-94, section 61,003, 129 Stat. 1312, 1773 ("critical electric infrastructure information means information … generated by or provided to the Commission or other Federal agency … that is designated as critical electric infrastructure information by the Commission or the Secretary pursuant to subsection (d)").

[194] As CEII information has to be designated by the CEII Coordinator or DOE Secretary, information that an entity creates and maintains without providing to the Commission has not been formally designated as CEII.

apply to how that entity may want to share its information.[195] Moreover, an entity may have information that could qualify as CEII, but such information is not CEII under the Commission's regulations unless it has been submitted to the Commission pursuant to the Commission's CEII regulations and the Commission has determined it to be CEII.

122. The Final Rule facilitates voluntary sharing by allowing the public to request CEII and by adding to the Commission's regulations a process whereby staff may share CEII in a proactive manner with a variety of entities. The Commission agrees with PJM's comments that existing non-public voluntary sharing mechanisms within the energy industry are sufficient to encourage sharing information among the different groups and therefore there is no need for the Commission to establish requirements for sharing within the industry through tariff revisions or otherwise.[196] It is also unnecessary to adopt Public Interest Organizations' and WIRAB's recommendation that the Commission establish "whitelists" for third parties to use or to require entities sharing information outside of the Commission's CEII process to adopt a particular NDA.

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[195] However, other concerns may influence how the entity shares its own information with others.

[196] Section 215A(d) requires the Commission "to promulgate [] regulations as necessary" to, *inter alia*, "facilitate voluntary sharing of critical electric infrastructure information." FAST Act, Pub. L. No. 114-94, section 61,003, 129 Stat. 1312, 1776. The FAST Act, therefore, affords the Commission with discretion in this regard and, at least implicitly, recognizes that the Commission may, identify, encourage and support existing processes to facilitate the voluntary sharing of CEII.

123. The Commission agrees with NERC and APPA that the plain language of the statute expressly provides for the voluntary sharing of information with entities like E-ISAC and other ISAOs. Section 215A(d)(2)(iv) concerns the voluntary sharing of CEII with, between, and by "information sharing and analysis centers established pursuant to Presidential Decision Directive 63." Pursuant to that provision, the Commission anticipates voluntary sharing of information with, between and by E-ISAC and other ISAOs under the appropriate circumstances. Under our current NDAs, CEII recipients may share CEII with other individuals covered by a NDA for the same information.[197] When information is provided in accordance with section 215A(d) the provisions for release from liability in section 215A(f)(3) would apply.

124. The Commission disagrees with APPA that E-ISAC or another ISAO should be designated as a forum to share CEII. The FAST Act does not specify that the Commission should designate E-ISAC, another ISAO, or any other entity as a forum through which CEII can be shared under section 215A. In fact, a plain reading of the statute indicates that Congress designated the Commission as the entity to facilitate this sharing. As such, the Commission declines to take the recommendation of APPA.

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[197] *See, e.g.*, Critical Energy Infrastructure Information General Non-Disclosure Agreement, https://www.ferc.gov/legal/ceii-foia/ceii/gen-nda.pdf ("A Recipient may only discuss CEII with another Recipient of the identical CEII. A Recipient may check with the CEII Coordinator to determine whether another individual is a Recipient of the identical CEII.").

125. We disagree with APPA's assertions that the voluntary sharing provision in the Commission's regulations effectively requires entities to share CEII with another entity or the Commission.[198] Section 215A(d)(6) explicitly states that an entity is not required to share CEII with the Commission or another entity or person.[199] The voluntary sharing provision does not impose a sharing requirement on entities; instead, it allows the Commission discretion to share, in certain circumstances, CEII that has already been submitted to, or generated by, the Commission.

126. Even if the Commission's voluntary sharing of information were viewed as the same as a third-party sharing it, the Commission must balance its obligation to disclose information as necessary to carry out its jurisdictional responsibilities against an entity's possible preference not to have such information disclosed.[200] The regulations adopted here achieve that balance. Furthermore, the FAST Act does not place limits on the Commission's ability to share information in its possession when authorized and necessary to carry out the requirements of the FAST Act or the Commission's other jurisdictional responsibilities.

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[198] FAST Act, Pub. L. No. 114-94, § 61,003, 129 Stat. 1312, 1777.

[199] *Id.*

[200] The FAST Act does not prohibit the Commission from disclosing any information, nor does it require an entity to produce any information. FAST Act, Pub. L. No. 114-94, section 61,003, 129 Stat. 1312, 1777.

127. As noted in the NOPR, in some circumstances, providing notice to a submitter of CEII that its information will be shared under section 215A could hamper the ability of the Commission to act in a timely way.[201] The Commission, therefore, disagrees with the comments by APPA and NRECA that prior notice must be provided in each instance where the Commissions uses the voluntary sharing provisions of section 215A. However, in response to the comments, the Commission clarifies in amended section 388.113(f) that the Commission will not provide advanced notice only in situations where there is an urgent need to disseminate the information. The Commission will also adopt MISO's and CEA's proposal that when prior notice is not given, the Commission will provide submitters of CEII whose information was shared with notice as soon as practicable.

128. The NOPR proposed to require that a consultation between the CEII Coordinator and the appropriate Office Director take place prior to any voluntary sharing of CEII. We disagree with NERC's proposal to add a requirement that staff from the Commission's Office of Electric Reliability (OER) and Office of Energy Infrastructure Security (OEIS) be involved in all voluntary sharing consultations because the information in question may not involve OEIS or OER subject matter. However, we note that the CEII Coordinator will consult with Commission staff as appropriate, which could include OER

[201] NOPR, 155 FERC ¶ 61,278 at P 38.

and OEIS staff. The Commission is also not persuaded that it is necessary to provide additional details regarding the factors the Commission will use to determine when voluntary sharing is appropriate. The NOPR specifically proposed that the Commission will voluntarily share "CEII with individuals and organizations that the Commission has determined need the information to ensure that energy infrastructure is protected."[202] Thus, the NOPR provided sufficient details on the circumstances in which the Commission will voluntarily share CEII. Providing more details may unnecessarily restrict the Commission's ability to voluntarily share needed information.

129. The Commission disagrees with APPA's suggestion that the regulations should include more developed protections to facilitate information sharing. [203] The Commission believes that procedures outlined in the NOPR are sufficient to protect CEII that the Commission shares. When the Commission voluntarily shares information, CEII will be shared subject to an appropriate NDA or Acknowledgement and Agreement.[204] Moreover, under section 388.113(f), the Commission may impose additional conditions

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[202] NOPR, 155 FERC ¶ 61,278 at P 37.

[203] *Id.* PP 31-32

[204] As noted below, to obtain CEII federal agencies execute an Acknowledgement and Agreement, as opposed to a NDA. *See* Federal Agency Acknowledgement and Agreement, http://www.ferc.gov/legal/ceii-foia/ceii/fed-agen-acknow-agree.pdf.

on how the information may be used and maintained that the Commission voluntarily shares.

130. In response to TAPS's comment, the Commission finds that the CEII Coordinator delegation in section 375.313 is sufficient and does not require separate delegations for Office Directors to voluntarily share CEII. Moreover, existing section 388.113(d)(1) has allowed Commission staff to share Critical Energy Infrastructure Information with facility owners and operators. No such delegated authority has been used for such sharing.

F. Request for Access to CEII

NOPR

131. The Commission proposed to maintain special access procedures for owner-operators of facilities, federal agencies, and intervening parties.[205] For intervenors, the Commission proposed to move the existing procedures in section 388.112 to section 388.113 and to eliminate the exemption for certain LNG materials.[206] For general requesters, the Commission added a one-year time limit for organizational requests and added back a time requirement for the Commission to process CEII requests.[207] The

[205] NOPR, 155 FERC ¶ 61,278 at PP 43-49.

[206] *Id.* P 49.

[207] *Id.* PP 50-51.

Commission also proposed adding a provision to clarify that the Commission's CEII regulations should not be construed to require the release of certain non-CEII.[208]

Comments

132. APPA recommends that the Commission adopt a tiered system with varying levels of access restrictions.[209] APPA and the Trade Associations suggest that the Commission create a distinct "need to know" standard to access information related to the bulk-power system.[210] Under this suggested standard, CEII would only be disclosed when the person or entity seeking the information has a direct "need to know" in order to maintain reliability, safety, or security.[211]

133. The Trade Associations recommend that if an academic institution or other members of the public request CEII, the Commission should deny the request and refer the request to the information owner.[212] Peak, on the other hand, supports data sharing with researchers and asks the Commission to permit researchers to access CEII data.[213]

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[208] *Id.* P 52.

[209] APPA Comments at 19.

[210] APPA Comments at 18; Trade Associations Comments at 27.

[211] APPA Comments at 9; Trade Associations Comments at 27.

[212] Trade Associations Comments at 32.

[213] Peak Comments at 7-8.

Peak also suggests that the Commission consider whether "research institutions with defined cyber security and employee background checks" should have a specific process for obtaining CEII.[214] WIRAB supports the Commission's balancing approach for determining who should receive CEII, but WIRAB recommends that the Commission delete the portion of proposed section 388.113(g)(iv) that states that the Commission can deny a request for "other reasons."[215]

134. Peak recommends that the Commission's sharing of CEII with owners and operators should not be limited to information related to "its own facility."[216]

135. Public Interest Organizations support the NOPR's proposed revisions allowing certain LNG materials to be accessible in proceedings in which there is a right to intervention.[217] Public Interest Organizations suggest that "the Commission streamline the release of CEII data for intervenors by allowing one request to trigger release of all of an entity's CEII data."[218]

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[214] *Id.* at 14.

[215] WIRAB Comments at 8.

[216] Peak Comments at 13.

[217] Public Interest Organizations Comments at 9.

[218] *Id.* at 9-10.

136. MISO notes that for purposes of consistency, the Commission should add language already in section 388.112(b)(iv) to amended section 388.113(g)(4) to ensure that, if an objection to a request for disclosure is filed, whether the information is privileged or CEII, "the filer shall not provide the non-public document to the person or class of persons identified in the objection until ordered by the Commission or a decisional authority."[219]

137. Peak asks the Commission to clarify whether the protections proposed in section 388.113(g)(2) regarding the obligation of federal agency recipients to protect CEII in the same manner as the Commission extends to data generated by a federal agency through an analysis of CEII.[220]

138. APS requests that the Commission revise amended section 388.113(g)(5)(vi) to require organizational requesters to promptly update/remove individuals from their list of approved individuals.[221]

139. The Trade Associations and APS state that they are concerned that amended section 388.113(g)(5)(v), which allows an individual under an organizational request to have access to CEII for the remainder of a calendar year, may result in a less robust

[219] MISO Comments at 4.

[220] Peak Comments at 13.

[221] APS Comments at 11; s*ee also* Trade Associations Comments at 35.

verification system.[222] WIRAB supports allowing requesters to maintain their validity for the duration of the calendar year.[223]

140. INGAA asks for acknowledgment that the Commission approves of entities providing requested information directly to CEII requesters.[224] INGAA also requests that proposed section 388.113(g)(5)(ix) be modified to add "information on rare species of plants and animals" to the list of items not required to be released through the CEII process.[225]

141. Public Interest Organizations ask the Commission to establish a reasonable timeline for the review of and response to CEII requests.[226] APS requests that the Commission add a default twenty-day time period to respond to CEII requests unless the information is needed in fewer than twenty days.[227] NERC suggests that the Commission

[222] Trade Associations Comments at 35; APS Comments at 10-11.

[223] WIRAB Comments at 9.

[224] INGAA Comments at 4.

[225] *Id.*

[226] Public Interest Organizations Comments at 10 (noting that it often takes 4-6 months to get access to Form No. 715 information through the existing Critical Energy Infrastructure Information process).

[227] APS Comments at 8.

add a provision indicating that the Commission may toll the response time when there is a need to gather further information from the requester.[228]

142. NERC requests that the appeal rights available to requesters be made available to submitting entities to avoid disclosures that might place CEII at risk.[229] TAPS asks for clarification that when conditions are imposed on a receipt of CEII, appeal rights will be granted.[230]

Commission Determination

143. APPA and the Trade Associations have not demonstrated a need for the Commission to change its practices and use a tiered system of categories of CEII or a heightened "need to know" standard for bulk-power system information. The Commission will continue to "balance the requestor's need for the information against the sensitivity of the information."[231] The Commission has utilized this balancing approach effectively in response to Critical Energy Infrastructure Information requests for almost fifteen years. The balancing approach has provided to individuals with a demonstrated need access to information subject to a NDA. However, in some instances,

[228] NERC Comments at 16 (citing 5 U.S.C. 552(a)(6)(B)(ii)).

[229] *Id.* at 18.

[230] TAPS Comments at 14.

[231] Section 388.113(g)(5)(iii).

the Commission has balanced a requester's asserted need for the information against its sensitivity and has determined not to produce certain types of CEII to the requester. The Commission will continue this balancing approach under the Final Rule.

144. As noted above, the FAST Act does not require changes to the Commission's existing process for accessing information. The CEII Coordinator will continue to evaluate each request individually. In response to Peak's comments, the Commission notes that the current procedures allow academics to obtain CEII, and that the Commission does, as appropriate in individual rulemakings, consider whether certain categories of information should generally be made available for research.[232] The Commission is not persuaded that any changes should be made to restrict or expand access to CEII by academics.

145. The Commission also disagrees with deleting the term "other reasons" from proposed section 388.113(g)(5)(iv) as there may be other legitimate reasons why the Commission would not permit access to certain CEII in particular situations.

146. The Commission is not persuaded that it needs to adopt Peak's proposed changes to the owner-operator provision. An owner-operator has a need to obtain CEII about its

[232] *See, e.g., Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, 156 FERC ¶ 61,215, at PP 93-95 (2016) (determining that geomagnetically induced current monitoring and magnetometer data will help facilitate geomagnetic disturbance research and concluding that such data typically should not be treated as confidential).

own facility. To the extent the owner-operator needs other CEII, it can pursue additional information through the regular CEII request process.

147. As to the comment by Public Interest Organizations, the Final Rule maintains the mechanism for interveners to request CEII outside of the CEII process.[233]

148. The Commission agrees with MISO's change to proposed section 388.113(g)(4), and amends that provision to include all of the language that currently exists in section 388.112(b)(2)(iv) to ensure that if an objection to the disclosure of CEII is filed, the information will not be disclosed until directed by the Commission or a decisional authority.

149. In response to Peak's comments, the Commission clarifies that a federal agency in receipt of CEII from the Commission must protect that information in the same manner as the Commission. That agency will be required to execute an appropriate Agency Acknowledgment and Agreement. We clarify that derivative analyses that use or rely on CEII, without actually disclosing CEII, do not automatically qualify as CEII unless the information provided could reasonably be expected to lead to the disclosure of CEII.[234]

150. Recognizing that the employment status and circumstances surrounding an individual or organization can change, in response to APS's comment, the Commission

[233] *See* section 388.113(g)(4).

[234] *See supra* P 64.

will modify the NDAs to indicate that a recipient of CEII must promptly notify the Commission if any changed conditions, such as a change in employment, occur.

151. Amended section 388.113(g)(5)(v) recognizes that in some instances a requester may request CEII multiple times during a calendar year. In response to comments by APS and Trade Associations regarding the robustness of the requester verifications, the Commission clarifies that each request will be reviewed by balancing the needs of the requester against the sensitivity of the requested information.

152. In response to INGAA's request, the Commission notes that under the current CEII rules, entities may share information that they submitted to the Commission with a request for CEII treatment (as opposed to CEII that they received from the Commission) directly with other entities, and the Commission will continue to encourage and support such a practice. The Commission adopts INGAA's recommendation that "information about rare species of plants and animals" be added to the section 388.113(g)(5)(ix) list of items that are not required to be released when the information is inextricably intertwined with CEII.

153. In response to comments by Public Interest Organizations, the Commission is not persuaded that additional clarifications regarding timing are necessary. Section 388.113(g)(5)(vii) of the amended regulations indicates that the time period for responding to CEII requests should mirror the period for responding to FOIA requests. In response to APS's suggestion of a default time period for the Commission to respond

to a request for CEII unless the information is needed sooner, expedited treatment is not needed, as a requester may include a timeframe in which it needs the information, and the Commission will endeavor to respond in that period. The Commission believes that NERC's recommendation to place language concerning tolling in the CEII regulation is not necessary, as the time requirement for responses to requesters is not binding and the Commission's practice is to always toll the response period when further information is needed.

154. In response to NERC's comment regarding appeal rights, the Commission notes that the existing CEII appeals process, which provides appeal rights to the requester, has been effective and there is no compelling need to extend a right to appeal to anyone other than the individual requester. If a submitter believes that its objection to disclosure of its CEII under a NDA has not been fully addressed, the submitter may raise that issue in district court.[235]

155. In response to TAPS's comment, the Commission clarifies that appeal rights apply when it imposes any conditions on receipt of CEII.

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[235] Because the challenge does not relate to the designation of the information, the action would not be under FPA section 215A(d)(11). *See supra* note 130; *see also Cortez III Serv. Corp v. NASA*, 921 F.Supp. 8, 11 (D.D.C. 1996) (holding, in a "reverse FOIA" action, that courts have jurisdiction over claims from parties that a release of their information would adversely affect them.")

III. Information Collection Statement

156. The Paperwork Reduction Act and Office of Management and Budget's (OMB) implementing regulations require OMB to review and approve certain information collection requirements imposed by agency rule.[236] This Final Rule does not impose any additional information collection requirements. [237] Therefore, the information collection regulations do not apply to this Final Rule.

IV. Environmental Analysis

157. 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.[238]

158. 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

[236] 5 CFR 1320.

[237] The current information collection requirements related to requesting access to CEII material are approved by OMB under FERC-603 (OMB Control No. 1902-0197).

[238] *Regulations Implementing National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

the effect of the regulations being amended.[239] The actions here fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act Certification

159. The Regulatory Flexibility Act of 1980 (RFA) requires rulemakings to contain either a description and analysis of the effect that the rule will have on small entities or a certification that the rule will not have a significant economic impact on a substantial number of small entities.[240] Rules that are exempt from the notice and comment requirements of section 553(b) of the Administrative Procedure Act are exempt from the RFA requirements. The Final Rule concerns rules of agency procedure and, therefore, an analysis under the RFA is not required.[241]

VI. Document Availability

160. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal

[239] 18 CFR 380.4(a)(2)(ii).

[240] 5 U.S.C. 603 (2012).

[241] 5 U.S.C. 553(b).

business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

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

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

VII. Effective Date and Congressional Notification

163. These regulations are effective 60 days from the date of 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 Enforcement Fairness Act of 1996. The Commission will submit the Final Rule to both houses of Congress and to the General Accountability Office.

List of Subjects in 18 CFR Part 375
Authority delegations (Government agencies); Seals and insignia; Sunshine Act.

List of Subjects in 18 CFR Part 388
Confidential business information; Freedom of information.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

In consideration of the foregoing, the Commission amends Parts 375 and 388, Chapter I, Title 18, Code of Federal Regulations, as follows:

PART 375— THE COMMISSION

1. The authority citation for part 375 continues to read as follows:

Authority: 5 U.S.C. 551-557; 15 U.S.C. 717-717w, 3301-3432; 16 U.S.C. 791-825r, 2601-2645; 42 U.S.C. 7101-7352.

2. In section 375.309, Paragraph (h) is added as follows:

Section 375.309 Delegations to the General Counsel.

* * * * *

(h) Deny or grant, in whole or in part, an appeal of a determination by the CEII Coordinator.

3. In section 375.313, Revising the section heading and paragraphs (a) and (b); Re-designating paragraphs (c) through (e) as paragraphs (d) through (f) and revising newly re-designated paragraphs (d) through (f); and adding a new paragraph (c).

Section 375.313 Delegations to the Critical Energy/Electric Infrastructure Information (CEII) Coordinator.

* * * * *

(a) Receive and review all requests for CEII as defined in section 388.113(c) of this chapter.

(b) Make determinations as to whether particular information fits within the definition of CEII found at section 388.113(c) of this chapter, including designating information, as appropriate.

(c) Make determinations that information designated as CEII should no longer be so designated when the unauthorized disclosure of the information could no longer be used to impair the security or reliability of the bulk-power system or distribution facilities or any other form of energy infrastructure.

(d) Make determinations as to whether a particular requester's need for and ability and willingness to protect CEII warrants limited disclosure of the information to the requester.

(e) Establish reasonable conditions on the release of CEII.

(f) Release CEII to requesters who satisfy the requirements in paragraph (d) of this section and agree in writing to abide by any conditions set forth by the Coordinator pursuant to paragraph (e) of this section.

PART 388— INFORMATION AND REQUESTS

1. The authority citation for part 388 is changed to read as follows:

Authority: 5 U.S.C. 301-305, 551, 552 (as amended), 553-557; 42 U.S.C. 7101-7352; 16 U.S.C. 824(o-l).

2. In section 388.112, the title is revised, and paragraphs (a), (b)(1), (b)(2)(i), (b)(2)(vi), (c)(1), and (d)-(e) are revised to read as follows:

Section 388.112 Requests for privileged treatment for documents submitted to the Commission

(a) *Scope.* By following the procedures specified in this section, any person submitting a document to the Commission may request privileged treatment for some or all of the information contained in a particular document that it claims is exempt from the mandatory public disclosure requirements of the Freedom of Information Act, 5 U.S.C. 552 (FOIA), and should be withheld from public disclosure. For the purposes of the Commission's filing requirements, non-CEII subject to an outstanding claim of exemption from disclosure under FOIA will be referred to as privileged material. The rules governing CEII are contained in 18 CFR 388.113.

(b) *Procedures for filing and obtaining privileged material.* (1) General Procedures. A person requesting that material be treated as privileged information must include in its filing a justification for such treatment in accordance with the filing procedures posted on the Commission's Web site at http://www.ferc.gov. A person requesting that a document filed with the Commission be treated as privileged in whole or in part must designate the document as privileged in making an electronic filing or clearly indicate a request for such treatment on a paper filing. The cover page and pages or portions of the document containing material for which privileged treatment is claimed should be clearly labeled in bold, capital lettering, indicating that it contains privileged or confidential information, as appropriate, and marked “DO NOT RELEASE.” The filer also must submit to the

Commission a public version with the information that is claimed to be privileged material redacted, to the extent practicable.

(2) Procedures for Proceedings with a Right to Intervene. ***

(i) If a person files material as privileged material in a complaint proceeding or other proceeding to which a right to intervention exists, that person must include a proposed form of protective agreement with the filing, or identify a protective agreement that has already been filed in the proceeding that applies to the filed material. This requirement does not apply to material submitted in hearing or settlement proceedings, or if the only material for which privileged treatment is claimed consists of landowner lists or privileged information filed under sections 380.12(f) and 380.16(f) of this chapter.

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(vi) For landowner lists, information filed as privileged under sections 380.12(f) and 380.16(f), forms filed with the Commission, and other documents not covered above, access to this material can be sought pursuant to a FOIA request under section 388.108 of this chapter. Applicants are not required under paragraph (b)(2)(iv) of this section

to provide intervenors with landowner lists and the other materials identified in the previous sentence.

(c) *Effect of privilege claim.* (1) For documents filed with the Commission:

(i) The documents for which privileged treatment is claimed will be maintained in the Commission's document repositories as non-public until such time as the Commission may determine that the document is not entitled to the treatment sought and is subject to disclosure consistent with section 388.108 of this chapter. By treating the documents as nonpublic, the Commission is not making a determination on any claim of privilege status. The Commission retains the right to make determinations with regard to any claim of privilege status, and the discretion to release information as necessary to carry out its jurisdictional responsibilities.

(ii) The request for privileged treatment and the public version of the document will be made available while the request is pending.

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(d) *Notification of request and opportunity to comment.* When a FOIA requester seeks a document for which privilege status has been claimed, or when the Commission itself is considering release of such information, the Commission official who will decide whether to release the information or any other appropriate Commission official will notify the person who submitted the document and give the person an opportunity (at

least five calendar days) in which to comment in writing on the request. A copy of this notice will be sent to the requester.

(e) *Notification before release.* Notice of a decision by the Commission, the Chairman of the Commission, the Director, Office of External Affairs, the General Counsel or General Counsel's designee, a presiding officer in a proceeding under part 385 of this chapter, or any other appropriate official to deny a claim of privilege, in whole or in part, will be given to any person claiming that the information is privileged no less than 5 calendar days before disclosure. The notice will briefly explain why the person's objections to disclosure are not sustained by the Commission. A copy of this notice will be sent to the FOIA requester.

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3. Revise section 388.113 to read as follows:

Section 388.113 Critical Energy/Electric Infrastructure Information (CEII)

(a) *Scope*. This section governs the procedures for submitting, designating, handling, sharing, and disseminating Critical Energy/Electric Infrastructure Information (CEII) submitted to or generated by the Commission. The Commission reserves the right to restrict access to previously filed information as well as Commission-generated information containing CEII. Nothing in this section limits the ability of any other Federal agency to take all necessary steps to protect information within its custody or control that is necessary to ensure the safety and security of the electric grid. To the

extent necessary, such agency may consult with the CEII Coordinator regarding the treatment or designation of such information.

(b) *Purpose*. The procedures in this section implement section 215A of the Federal Power Act, and provide a comprehensive overview of the manner in which the Commission will implement the CEII program.

(c) Definitions. For purposes of this section:

(1) *Critical electric infrastructure information* means information related to critical electric infrastructure, or proposed critical electrical infrastructure, generated by or provided to the Commission or other Federal agency other than classified national security information, that is designated as critical electric infrastructure information by the Commission or the Secretary of the Department of Energy pursuant to section 215A(d) of the Federal Power Act. Such term includes information that qualifies as critical energy infrastructure information under the Commission's regulations. Critical Electric Infrastructure Information is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552(b)(3) and shall not be made available by any Federal, State, political subdivision or tribal authority pursuant to any Federal, State, political subdivision or tribal law requiring public disclosure of information or records pursuant to section 215A(d)(1)(A) and (B) of the Federal Power Act.

(2) *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;

(iii) Is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552; and

(iv) Does not simply give the general location of the critical infrastructure.

(3) *Critical electric infrastructure* means a system or asset of the bulk-power system, whether physical or virtual, the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters.

(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.

(d) *Criteria and Procedures for determining what constitutes CEII*. The following criteria and procedures apply to information labeled as CEII:

(1) For information submitted to the Commission:

(i) A person requesting that information submitted to the Commission be treated as CEII must include with its submission a justification for such treatment in accordance with the filing procedures posted on the Commission's website at http://www.ferc.gov. The justification must provide how the information, or any portion of the information, qualifies as CEII, as the terms are defined in paragraphs (c)(1) and (2) of this section. The submission must also include a clear statement of the date the information was submitted to the Commission, how long the CEII designation should apply to the information and support for the period proposed. Failure to provide the justification or other required information could result in denial of the designation and release of the information to the public.

(ii) In addition to the justification required by paragraph (d)(1)(i) of this section, a person requesting that information submitted to the Commission be treated as CEII must clearly label the cover page and pages or portions of the information for which CEII treatment is claimed in bold, capital lettering, indicating that it contains CEII, as appropriate, and marked "DO NOT RELEASE." The submitter must also segregate those portions of the information that contain CEII (or information that reasonably could be expected to lead to the disclosure of the CEII) wherever feasible. The

submitter must also submit to the Commission a public version with the information where CEII is redacted, to the extent practicable.

(iii) If a person files material as CEII in a complaint proceeding or other proceeding to which a right to intervention exists, that person must include a proposed form of protective agreement with the filing, or identify a protective agreement that has already been filed in the proceeding that applies to the filed material.

(iv) The information for which CEII treatment is claimed will be maintained in the Commission's files as non-public until such time as the Commission may determine that the information is not entitled to the treatment sought. By treating the information as CEII, the Commission is not making a determination on any claim of CEII status. The Commission retains the right to make determinations with regard to any claim of CEII status at any time, and the discretion to release information as necessary to carry out its jurisdictional responsibilities. Although unmarked information may be eligible for CEII treatment, the Commission will treat unmarked information as CEII only if it is properly designated as CEII pursuant to Commission regulations.

(v) The CEII Coordinator will evaluate whether the submitted information or portions of the information are covered by the definitions in paragraphs

(c)(1) and (2) of this section prior to making a designation as CEII.

(vi) Subject to the exceptions set forth in section 388.113(f)(5), when a CEII requester seeks information for which CEII status has been claimed, or when the Commission itself is considering release of such information, the CEII Coordinator or any other appropriate Commission official will notify the person who submitted the information and give the person an opportunity (at least five business days) in which to comment in writing on the request. A copy of this notice will be sent to the requester. Notice of a decision by the Commission, or the CEII Coordinator to make a release of CEII, will be given to any person claiming that the information is CEII no less than five business days before disclosure. The notice will respond to any objections to disclosure from the submitter that are not sustained. Where applicable, a copy of this notice will be sent to the CEII requester.

(2) For Commission-generated information:

(i) After consultation with the Office Director for the office that created the information, or the Office Director's designee, the CEII Coordinator will designate Commission-generated information as CEII after determining that the information or portions of the information are covered by the definitions in paragraphs (c)(1) and (2) of this section. Commission-generated CEII shall include clear markings to indicate the information is

CEII and the date of the designation.

(ii) The Commission will segregate non-CEII from Commission-generated CEII or information that reasonably could be expected to lead to the disclosure of CEII wherever feasible.

(e) *Duration of the CEII designation*. All CEII designations will be subject to the following conditions:

(1) A designation may last for up to a five-year period, unless re-designated. In making a determination as to whether the designation should be extended, the CEII Coordinator will take into account information provided in response to paragraph (d)(1)(i) of this section, and any other information, as appropriate.

(2) A designation may be removed at any time, in whole or in part, if the Commission determines that the unauthorized disclosure of CEII could no longer be used to impair the security or reliability of the bulk-power system or distribution facilities or any other form of energy infrastructure.

(3) The Commission will treat CEII or documents marked as CEII as non-public after the designation has lapsed until the CEII Coordinator determines to un-designate the information.

(4) If a CEII designation is removed, the submitter will receive notice and an opportunity to comment. The CEII Coordinator will notify the submitter of the information and give the submitter an opportunity (at least five business days) in

which to comment in writing prior to the removal of the designation. Notice of a removal decision will be given to any submitter claiming that the information is CEII no less than five business days before disclosure. The notice will briefly explain why the submitter's objections to the removal of the designation are not sustained by the Commission

(f) *Voluntary sharing of CEII*. The Commission, taking into account standards of the Electric Reliability Organization, will facilitate voluntary sharing of CEII with, between, and by Federal, state, political subdivision, and tribal authorities; the Electric Reliability Organization; regional entities; information sharing and analysis centers established pursuant to Presidential Decision Directive 63; owners, operators, and users of critical electric infrastructure in the United States; and other entities determined appropriate by the Commission. The process will be as follows:

(1) The Director of any Office of the Commission or his designee that wishes to voluntarily share CEII shall consult with the CEII Coordinator prior to the Office Director or his designee making a determination on whether to voluntarily share the CEII.

(2) Consistent with section 388.113(d) of this Chapter, the Commission retains the discretion to release information as necessary to carry out its jurisdictional responsibilities in facilitating voluntary sharing or, in the case of information provided to other federal agencies, the Commission retains the discretion to

release information as necessary for those agencies to carry out their jurisdictional responsibilities.

(3) All entities receiving CEII must execute either a non-disclosure agreement or an acknowledgement and agreement. A copy of each agreement will be maintained by the Office Director with a copy to the CEII Coordinator.

(4) When the Commission voluntarily shares CEII pursuant to this subsection, the Commission may impose additional restrictions on how the information may be used and maintained.

(5) Submitters of CEII shall receive notification of a limited release of CEII no less than five business days before disclosure, except in instances where voluntary sharing is necessary for law enforcement purposes, to maintain infrastructure security, to address potential threats, when notice would not be practicable, and where there is an urgent need to quickly disseminate the information. When prior notice is not given, the Commission will provide submitters of CEII notice of a limited release of the CEII as soon as practicable.

(g) *Accessing CEII.*

(1) An owner/operator of a facility, including employees and officers of the owner/operator, may obtain CEII relating to its own facility, excluding Commission-generated information except inspection reports/operation reports and any information directed to the owner-operators, directly from Commission

staff without going through the procedures outlined in paragraph (g)(5) of this section. Non-employee agents of an owner/operator of such facility may obtain CEII relating to the owner/operator's facility in the same manner as owner/operators as long as they present written authorization from the owner/operator to obtain such information. Notice of such requests must be given to the CEII Coordinator, who shall track this information.

(2) An employee of a federal agency acting within the scope of his or her federal employment may obtain CEII directly from Commission staff without following the procedures outlined in paragraph (g)(5) of this section. Any Commission employee at or above the level of division director or its equivalent may rule on requests for access to CEII by a representative of a federal agency. To obtain access to CEII, an agency employee must sign an acknowledgement and agreement, which states that the agency will protect the CEII in the same manner as the Commission and will refer any requests for the information to the Commission. Notice of each such request also must be given to the CEII Coordinator, who shall track this information.

(3) A landowner whose property is crossed by or in the vicinity of a project may receive detailed alignment sheets containing CEII directly from Commission staff without submitting a non-disclosure agreement as outlined in paragraph (g)(5) of

this section. A landowner must provide Commission staff with proof of his or her property interest in the vicinity of a project.

(4) Any person who is a participant in a proceeding or has filed a motion to intervene or notice of intervention in a proceeding may make a written request to the filer for a copy of the complete CEII version of the document without following the procedures outlined in paragraph (g)(5) of this section. The request must include an executed copy of the applicable protective agreement and a statement of the person's right to party or participant status or a copy of the person's motion to intervene or notice of intervention. Any person may file an objection to the proposed form of protective agreement. A filer, or any other person, may file an objection to disclosure, generally or to a particular person or persons who have sought intervention. If no objection to disclosure is filed, the filer must provide a copy of the complete, non-public document to the requesting person within five business days after receipt of the written request that is accompanied by an executed copy of the protective agreement. If an objection to disclosure is filed, the filer shall not provide the non-public document to the person or class of persons identified in the objection until ordered by the Commission or a decisional authority.

(5) If any requester not described above in paragraph (g)(1)-(4) of this section has a particular need for information designated as CEII, the requester may request the information using the following procedures:

(i) File a signed, written request with the Commission's CEII Coordinator. The request must contain the following:

(a) Requester's name (including any other name(s) which the requester has used and the dates the requester used such name(s)), title, address, and telephone number; and the name, address, and telephone number of the person or entity on whose behalf the information is requested;

(b) A detailed Statement of Need, which must state: the extent to which a particular function is dependent upon access to the information; why the function cannot be achieved or performed without access to the information; an explanation of whether other information is available to the requester that could facilitate the same objective; how long the information will be needed; whether or not the information is needed to participate in a specific proceeding (with that proceeding identified); and an explanation of whether the information is needed expeditiously.

(c) An executed non-disclosure agreement as described in paragraph (h)(2) of this section;

(d) A signed statement attesting to the accuracy of the information provided in the request; and

(e) A requester shall provide his or her date and place of birth upon request, if it is determined by the CEII Coordinator that this information is necessary to process the request.

(ii) A requester who seeks the information on behalf of all employees of an organization should clearly state that the information is sought for the organization, that the requester is authorized to seek the information on behalf of the organization, and that all individuals in the organization that have access to the CEII will agree to be bound by a non-disclosure agreement that must be executed.

(iii) After the request is received, the CEII Coordinator will determine if the information is CEII, and, if it is, whether to release the CEII to the requester. The CEII Coordinator will balance the requester's need for the information against the sensitivity of the information. If the requester is determined to be eligible to receive the information requested, the CEII Coordinator will determine what conditions, if any, to place on release of the information.

(iv) If the CEII Coordinator determines that the CEII requester has not demonstrated a valid or legitimate need for the CEII or that access to the

CEII should be denied for other reasons, this determination may be appealed to the General Counsel pursuant to section 388.110 of this Chapter. The General Counsel will decide whether the information is properly classified as CEII, which by definition is exempt from release under FOIA, and whether the Commission should in its discretion make such CEII available to the CEII requester in view of the requester's asserted legitimacy and need.

(v) Once a CEII requester has been verified by Commission staff as a legitimate requester who does not pose a security risk, his or her verification will be valid for the remainder of that calendar year. Such a requester is not required to provide detailed information about himself or herself with subsequent requests during the calendar year. He or she is also not required to file a non-disclosure agreement with subsequent requests during the calendar year because the original non-disclosure agreement will apply to all subsequent releases of CEII.

(vi) An organization that is granted access to CEII pursuant to paragraph (g)(5)(ii) of this section may seek to add additional individuals to the non-disclosure agreement within one (1) year of the date of the initial CEII request. Such an organization must provide the names of the added individuals to the CEII Coordinator and certify that notice of each added

individual has been given to the submitter. Any newly added individuals must execute a supplement to the original non-disclosure agreement indicating their acceptance of its terms. If there is no written opposition within five business days of notifying the CEII Coordinator and the submitter concerning the addition of any newly added individuals, the CEII Coordinator will issue a standard notice accepting the addition of these names to the non-disclosure agreement. If the submitter files a timely opposition with the CEII Coordinator, the CEII Coordinator will issue a formal determination addressing the merits of such opposition. If an organization that is granted access to CEII pursuant to paragraph (g)(5)(ii) of this section wants to add new individuals to its non-disclosure agreement more than one year after the date of its initial CEII request, the organization must submit a new CEII request pursuant to paragraph (g)(5)(ii) of this section and a new non-disclosure agreement for each new individual added.

(vii) The CEII Coordinator will attempt to respond to the requester under this section according to the timing required for responses under the FOIA in section 18 CFR 388.108(c).

(viii) Fees for processing CEII requests will be determined in accordance with section 18 CFR 388.109.

(ix) Nothing in this section should be construed as requiring the release of

proprietary information, personally identifiable information, cultural resource information, information on rare species of plants and animals, and other comparable data protected by statute or any privileged information, including information protected by the deliberative process privilege.

(h) *Duty to protect CEII*. Unauthorized disclosure of CEII is prohibited.

(1) To ensure that the Commissioners, Commission employees, and Commission contractors protect CEII from unauthorized disclosure, internal controls will describe the handling, marking, and security controls for CEII.

(2) Any individual who requests information pursuant to paragraph (g)(5) of this section must sign and execute a non-disclosure agreement, which indicates the individual's willingness to adhere to limitations on the use and disclosure of the information requested. The non-disclosure agreement will, at a minimum, require the following: CEII will only be used for the purpose for which it was requested; CEII may only be discussed with authorized recipients; CEII must be kept in a secure place in a manner that would prevent unauthorized access; CEII must be destroyed or returned to the Commission upon request; the Commission may audit the recipient’s compliance with the non-disclosure agreement; CEII provided pursuant to the agreement is not subject to release under either FOIA or Sunshine Laws; a recipient is obligated to protect the CEII even after a designation has

lapsed until the CEII Coordinator determines the information should no longer be designated as CEII under subsection (e)(2); and a recipient is required to promptly report all unauthorized disclosures of CEII to the Commission.

(i) *Sanctions*. Any officers, employees, or agents of the Commission who knowingly and willfully disclose CEII in a manner that is not authorized under this section will be subject to appropriate sanctions, such as removal from the federal service, or possible referral for criminal prosecution. Commissioners who knowingly and willfully disclose CEII without authorization may be referred to the Department of Energy Inspector General. The Commission will take responsibility for investigating and, as necessary, imposing sanctions on its employees and agents.

(j) *Administrative Appeals of CEII determinations*.

(1) Submitters who receive a determination that the Commission intends to remove a CEII designation may appeal that determination. The submitter must file notice of its intent to appeal that determination within five business days of the determination. The notice of intent to file an appeal must be sent to the General Counsel, with a copy to the CEII Coordinator. A statement in support of the notice of appeal must be submitted to the General Counsel within 20 business days of the date of the determination. The appeal will be considered received upon receipt of the statement in support of the notice of appeal.

(2) Individuals who receive a determination denying a request for the release of

CEII, in whole or in part, or a determination denying a request to change the designation of CEII may appeal such determinations. Such appeals must be submitted to the General Counsel within 20 business days of the date of the determination.

(3) The Commission's General Counsel or the General Counsel's designee will make a determination with respect to any appeal within 20 business days after the receipt of the appeal. If, on appeal, the General Counsel or the General Counsel's designee upholds the determination in whole or in part, then the General Counsel or the General Counsel's designee will notify the person submitting the appeal of the availability of judicial review.

(4) The time limits prescribed for the General Counsel or his designee to act on an appeal may be extended pursuant to section 388.110(b)(1).

(5) Prior to seeking judicial review in federal district court pursuant to section 215A(d)(11) of the Federal Power Act, a person who received a determination from the Commission concerning a CEII designation must first appeal the determination to the Commission's General Counsel.

Note: The following appendix will not appear in the Code of Federal Regulations

Appendix

Initial Comments

Abbreviation	Commenter
APPA	American Public Power Association
CEA	Canadian Electricity Association
HRC	Hydropower Reform Coalition
INGAA	Interstate Natural Gas Association of America
ITC	International Transmission Company d/b/a ITC*Transmission*, Michigan Electric Company, LLC, ITC Midwest LLC, and ITC Great Plains LLC
Joint RTOs	ISO New England, Inc. and Southwest Power Pool, Inc.
MISO	Midcontinent Independent System Operator, Inc.
NRECA	National Rural Electric Cooperative Association
NERC	North American Electric Reliability Corporation
NRC	Nuclear Regulatory Commission
Peak	Peak Reliability
Powerex	Powerex Corp.
Public Interest Organizations	Alliance for Affordable Energy, Citizens Action Coalition of Indiana, Inc., Citizens Utility Board, Fresh Energy, Great Plains Institute, Natural Resources Defense Council, Sierra Club Environmental Law Program, Southern Environmental Law Center, Sustainable FERC Project, Union of Concerned Scientists, Utah Clean Energy, VoeSolar, Western Grid Group, Western Resource Advocates, and Wind on the Wires
Tacoma Power	City of Tacoma, Department of Public Utilities, Light Division d.b.a. Tacoma Power (Tacoma Power)
Tallgrass Pipelines	Rockies Express Pipeline LLC, Tallgrass Interstate Gas, Transmission, LLC, and Trailblazer Pipeline Company LLC
TAPS	Transmission Access Policy Study Group
Trade Associations	Edison Electric Institute, Electric Power Supply Association, and Electricity Consumers Resource

	Council
WIRAB	Western Interconnection Regional Advisory Board

Reply Comments

Abbreviation	**Commenter**
PJM	PJM Interconnection, LLC
Joint RTOs	ISO New England, Inc. and Southwest Power Pool, Inc.

157 FERC ¶ 61,043
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, and Colette D. Honorable.

North American Electric Reliability Corporation Docket No. RR16-6-000

ORDER ACCEPTING 2017 BUSINESS PLANS AND BUDGETS

(Issued October 20, 2016)

1. On August 23, 2016, the North American Electric Reliability Corporation (NERC) filed 2017 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 2017 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 2017 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

[1] The eight Regional Entities are Florida Reliability Coordinating Council (FRCC); Midwest Reliability Organization (MRO); Northeast Power Coordinating Council, Inc. (NPCC); Reliability*First* Corporation (Reliability*First*); SERC Reliability Corporation (SERC); Southwest Power Pool Regional Entity (SPP RE); Texas Reliability Entity (Texas RE); and Western Electricity Coordinating Council (WECC).

Reliability 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 the 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.

[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) (2016).

B. NERC Application

4. The NERC Application contains NERC's proposed business plan and budget for the year ending December 31, 2017, as well as the proposed business plans and budgets of each of the eight Regional Entities and WIRAB for the year ending December 31, 2017.

5. NERC states that it prepared its 2017 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 2017 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.

6. NERC states that the proposed assessment for the total ERO (i.e., NERC, the Regional Entities, and WIRAB) for 2017 allocable to the United States is $154,832,467, which includes $54,326,337 for NERC funding; $99,746,574 for Regional Entity funding; and $759,556 for WIRAB funding.[8] NERC states that it will continue to allocate costs to end users in the United States based on net energy for load. NERC states that its proposed total United States net funding requirement for the ERO enterprise is equivalent to $0.0000389 per kWh, based on the aggregate net energy for load of the United States in 2015.[9]

7. In addition to the NERC, Regional Entity, and WIRAB business plans and budgets, the NERC Application contains various attachments including: Discussion of Comments Received During Development of NERC's 2017 Business Plan and Budget (Attachment 12); Calculation of Adjustments for Alberta Electric System Operator, Ontario Independent Electric System Operator, New Brunswick and the Quebec NERC Assessment (Attachment 13); Metrics Comparing Regional Entity Operations Based on 2017 Budgets (Attachment 14); and Metrics on NERC and Regional Entity Administrative (Indirect) Costs Based on the 2016 and 2017 Budgets (Attachment 15).

[8] NERC Application, Attachment 1 (Summary Tables for NERC and Regional Entity Proposed 2017 Budgets and Assessments) at 2, Attachment 11 (Western Interconnection Regional Advisory Body Proposed 2017 Business Plan and Budget) at 3.

[9] *Id.* at 37.

8. On September 23, 2016, NERC submitted a supplemental filing clarifying certain aspects of NPCC's and Reliability*First*'s business plans and budgets (NERC Supplemental Filing).

II. Notices and Responsive Pleadings

9. Notice of NERC's August 23, 2016 filing was published in the *Federal Register*, 81 Fed. Reg. 59,617 (Aug. 30, 2016), with interventions and protests due on or before September 13, 2016.

10. On September 13, 2016, WIRAB filed advice pursuant to section 215(j) of the FPA stating it reviewed WECC's 2017 business plan and budget, and finds all of the proposed activities to be eligible and appropriate for funding under section 215 of the FPA.[10]

11. Notice of NERC's supplemental filing was published in the *Federal Register*, 81 Fed. Reg. 66,952 (Sept. 29, 2016), with interventions and protests due on or before September 30, 2016. No interventions or protests were filed.

III. Discussion

A. NERC Business Plan and Budget

12. NERC states that its strategic goals and objectives for 2017 are focused on the following areas: (1) maintaining timely and risk-responsive Reliability Standards; (2) conducting objective and risk-informed compliance monitoring, enforcement, and organization certification and registration activities; (3) identifying and mitigating significant current risks to reliability; (4) identifying and assessing emerging risks to reliability; and (5) operating the ERO enterprise in an effective, efficient, and collaborative manner that improves transparency, consistency, quality, effectiveness, cost-effectiveness, and timeliness of results.[11]

13. NERC states that its 2017 business plan and budget is based on the following program areas: (1) Reliability Standards; (2) Compliance Monitoring and Enforcement Program and Organization Registration and Certification; (3) Reliability Assessment and System Analysis; (4) Performance Analysis; (5) Reliability Risk Management, which is comprised of Situation Awareness and Event Analysis; (6) Electricity Information Sharing and Analysis Center; and (7) Training, Education, and Operator Certification.[12]

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[10] 16 U.S.C. § 824o(j).

[11] NERC Application at 7.

[12] *Id.* at 3-4.

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 (FTE), as well as the FTEs budgeted for 2017. NERC also provides 2016 accepted budget data and 2016 year-end projected data for comparison to the 2017 proposed budget data.

14. NERC's proposed total funding requirement for 2017 is $69,602,175, which is an increase of $2,415,510 (3.6 percent) over NERC's 2016 budget.[13] NERC's proposed 2017 net funding requirement is $59,856,314 (i.e., total budget less funding from other sources), of which $54,326,337 is allocated to the United States.[14] The net funding requirement allocated to the United States is an increase of $2,540,509 (4.9 percent) over the 2016 budget proposal.

15. NERC states that the proposed 2017 business plan and budget reflects a provision for working capital and operating reserve funding in the amount of $530,402.[15] Finally, NERC proposes a 2017 staffing level of 189.9 FTEs, a decrease of 2.5 FTEs from 2016 budget staffing levels.[16]

16. NERC states that it received $500,000 in penalty monies for the period of July 1, 2015 through June 30, 2016.[17] In accordance with the Commission's June 18, 2015 order,[18] 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 deposit the $500,000 of penalty monies into its assessment stabilization reserve.[19] NERC also requests approval to use $1,100,000 of funds from the assessment stabilization reserve to reduce 2017 assessments.[20]

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[13] *Id.* at 8.

[14] *Id.* at 22. NERC's other funding sources are penalty payments; third-party funding for the Cyber Risk Information Sharing Program; revenue from services and software; testing and workshop fees; and interest. *Id.* at 21-22.

[15] *Id.* at 21.

[16] *Id.* at 42, Attachment 2 at 12.

[17] *Id.* at 79.

[18] *North American Electric Reliability Corp.*, 151 FERC ¶ 61,225, at P 19 (2015).

[19] NERC Application at 79.

[20] *Id.*

Commission Determination

17. We accept NERC's 2017 business plan and budget. We find that NERC's 2017 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 exception under section 1107 of the NERC Rules of Procedure and allow NERC to allocate $500,000 in penalty monies to its assessment stabilization reserve. We note that the decision here is limited to this case. Any future requests for exception to section 1107.2 of the NERC Rules of Procedure will be addressed based on the facts at that time.

B. Regional Entity Business Plans and Budgets

18. NERC's Application includes the 2017 business plans and budgets of each Regional Entity. 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.[21]

19. In the 2016 Budget Order, the Commission directed WECC to include additional information in its 2017 business plan and budget.[22] Specifically, the Commission directed WECC to include information on any further payments made and to be made for penalties imposed on WECC.[23]

20. In the instant filing, WECC complied with the 2016 Budget Order, including additional information regarding its civil penalty sanctions. Specifically, WECC noted that it has a $1M remaining liability associated with the 2011 Arizona-Southern California outage, which will be paid in May 2017 and is included in accrued expenses on WECC's balance sheet. WECC states that the penalties do not impact WECC's 2017 budget.[24]

21. In its supplemental filing, NERC states that certain aspects of its original filing may require clarification. Specifically, NERC notes that NPCC's business plan and

[21] *Id.* at 30.

[22] *North American Electric Reliability Corp.*, 153 FERC ¶ 61,134 (2015) (2016 Budget Order).

[23] *Id.* P 54.

[24] NERC Application, Attachment 10 (Western Electricity Coordinating Council's Proposed 2017 Business Plan and Budget) at 45.

budget filing states: "In order to reflect and respect the international membership and nature of NPCC, any sub-regional reliability assessment costs in response to U.S. only regulatory initiatives will be considered for allocation to U.S. only [balancing authority areas] consistent with NERC Rules of Procedure section 1102."[25] NERC clarifies that NPCC is not proposing any allocation of any specific "sub-regional reliability assessment costs in response to U.S. only regulatory initiatives" to U.S.-only balancing authority areas, nor is NPCC requesting pre-approval of any such allocation. NERC states that any such allocation could and would be requested only in a future year's business plan and budget filing (or in a supplemental filing requesting approval to revise assessments) based on specific activities and costs and with complete supporting information.[26]

22. Additionally, NERC notes that Reliability*First*'s business plan and budget includes a table that shows $250,000 of penalty sanction funds released from restriction on January 1, 2016 being placed into Reliability*First*'s operating reserve during 2016.[27] NERC also notes that the "Explanation of the Working Capital Reserve" included with that table states that "Reliability*First*'s proposed increase in its target Working Capital Reserve [for 2017] to $2,399,357 'is being funded by the 2015 budget under run and the penalty dollars that will be released in 2017.'"[28] However, NERC further observes that the table shows that the full amount of penalties collected during the 12 months ended June 30, 2016, $659,000, is being used to reduce the 2017 statutory assessments.[29] NERC clarifies that Reliability*First* used its penalty collections for the 12 months ended June 30, 2015 solely to reduce 2016 assessments, and that Reliability*First* is proposing to use its penalty collections for the 12 months ended June 30, 2016 solely to reduce 2017 assessments. NERC includes a revised version of Reliability*First*'s table to reflect these clarifications in its Supplemental Filing.

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[25] NERC Supplemental Filing at 1 (quoting NERC Application, Attachment 5 (Northeast Power Coordinating Council, Inc. Proposed 2017 Business Plan and Budget) at 59-61).

[26] NERC Supplemental Filing at 2.

[27] NERC Supplemental Filing at 2-3 (citing NERC Application, Attachment 6 (Reliability*First* Corporation Proposed 2017 Business Plan and Budget) at 53).

[28] NERC Supplemental Filing at 3 (citing NERC Application, Attachment 6 at 53).

[29] *Id.*

Commission Determination

23. We find that each Regional Entity submission, as supplemented with respect to NPCC and Reliability*First*, 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, as supplemented.

C. WIRAB Business Plan and Budget

24. WIRAB proposes statutory expenses of $1,229,080 in 2017, which is a $141,194 decrease from its 2016 budget.[30] To fund its operations in 2017, WIRAB proposes a statutory assessment of $901,452, of which $759,556 would be allocable to end users in the United States.[31]

25. WIRAB notes that its proposed key activities in 2017 include the following: (1) encouraging WECC and Peak Reliability, the reliability coordinator for the Western Interconnection, to set strategic planning priorities and align budgets and work plans based on rigorous analyses of existing and emerging risks to reliability in the Western interconnect; (2) encouraging Peak Reliability and WECC to develop policies to protect critical electricity infrastructure information (CEII) and promote sharing of non-CEII data with third parties to foster research and development; (3) encouraging WECC to systemically assess availability of essential reliability services under a wide range of future resource scenarios; and (4) encouraging and working with Peak Reliability to identify, disseminate, and promote best operational practices. WIRAB's budget includes 5.5 FTEs for 2017, which is the same as in its 2016 budget.

Commission Determination

26. Based on the information provided in the instant filing, we conclude that WIRAB's 2017 budget is reasonable and, accordingly, we accept the WIRAB 2017 budget.

The Commission orders:

(A) NERC's 2017 business plan and budget is hereby accepted.

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[30] NERC Application at 32.

[31] NERC Application, Attachment 11 at 3.

(B) The Regional Entities' 2017 business plans and budgets, as supplemented, are hereby accepted.

(C) WIRAB's 2017 business plan and budget is hereby accepted.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

SUNSHINE ACT MEETING NOTICE

November 10, 2016

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 17, 2016 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/ sing the eLibrary link, or may be examined in the Commission's Public Reference Room.

1032ND - MEETING

REGULAR MEETING

November 17, 2016

10:00 AM

Item No	Docket No.	Company
		ADMINISTRATIVE
A-1	AD16-1-000	Agency Administrative Matters
A-2	AD16-7-000	Customer Matters, Reliability, Security and Market Operations
A-3	AD07-13-010	2016 Report on Enforcement
A-4	AD17-3-000	Presentation on the Commission’s Dam Safety Program
		ELECTRIC
E-1	RM16-23-000	Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators
	AD16-20-000	Electric Storage Participation in Regions with Organized Wholesale Electric Markets
E-2	RM16-5-000	Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators
E-3	RM16-6-000	Essential Reliability Services and the Evolving Bulk-Power System--Primary Frequency Response
E-4	RM16-15-000	Regulations Implementing FAST Act Section 61003 - Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information
	RM15-25-001	Availability of Certain North American Electric Reliability Corporation Databases to the Commission
E-5	ER16-2528-000	Midcontinent Independent System Operator, Inc.
E-6	ER17-144-000	New York Independent System Operator, Inc.
E-7	TS16-1-000	NorthWestern Corporation

E-8	TS15-3-000	City of Rochester, Minnesota Board of Public Utilities
E-9	ER16-2437-000	Alcoa Power Generating Inc.
E-10	ER13-108-001	Alcoa Power Generating Inc.
E-11	EL16-105-000	Goodyear Tire & Rubber Company v. Entergy Texas, Inc.
E-12	ER16-453-000 ER16-453-001	PJM Interconnection, L.L.C. and Northeast Transmission Development, LLC
E-13	ER15-2294-000 ER15-2294-002	Pacific Gas and Electric Company
E-14	ER05-6-124	Midwest Independent Transmission System Operator, Inc.
	EL04-135-126 EL02-111-145 EL03-212-140	Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, LLC Ameren Services Company
E-15	ER15-2239-000 ER15-2239-001	NextEra Energy Transmission West, LLC

MISCELLANEOUS

M-1	RM17-5-000	Regulations Implementing the FOIA Improvement Act of 2016 and Clarifying the FOIA Regulations

HYDRO

H-1	RM16-19-000	Annual Charges for Use of Government Lands in Alaska
H-2	P-2307-075 P-12379-051	Alaska Electric Light and Power
	P-8221-098	Alaska Energy Authority
	P-2170-054	Chugach Electric Association
	P-420-088 P-1922-048 P-11841-031	Ketchikan Public Utilities
	P-2742-037	Copper Valley Electric Association
	P-2911-042 3015-018	Southeast Alaska Power Agency
H-3	RM17-4-000	Establishing the Length of License Terms for Hydroelectric Projects

H-4	P-2114-279	Public Utility District No. 2 of Grant County, Washington
H-5	P-14754-001	Rivertec Partners, LLC

CERTIFICATES

C-1	CP16-18-000	Magnum Gas Storage, LLC

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 Danelle Springer or David Reininger at 703-993-3100.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in the Commission Meeting Room. Members of the public may view this briefing in the designated overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

November 2016
Commission Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its November 17, 2016 public meeting. The summaries are produced by FERC's Office of External Affairs and are intended to provide only a general synopsis of the orders. These summaries are not intended as a substitute for the Commission's official orders. To determine the specific actions and the Commission's reasoning, please consult the individual orders when they are posted to FERC's eLibrary found at www.ferc.gov.

A-3 – Press Release
E-1 – Press Release
E-2 – Press Release
E-3 – Press Release
E-4 – Press Release
H-3 & H-1 – Press Release

FERC accepts request to terminate an agreement

E-5, *Midcontinent Independent System Operator, Inc.*, Docket No. ER16-2528-000. The order accepts MISO's request to terminate its System Support Resource Agreement with White Pine Electric Power, LLC for White Pine Unit No. 1.

FERC grants a limited, temporary waiver

E-6, *New York Independent System Operator, Inc.*, Docket No. ER17-144-000. This order grants NYISO's request for a limited, temporary waiver of its obligation under the 1993 PARs Facilities Agreement to settle, on a monthly basis, certain amounts associated with the phase angle regulators (PARs) at the Ramapo terminal that are charged to transmission owners in PJM Interconnection, L.L.C. NYISO explained that Consolidated Edison Company of New York, Inc., the New York Transmission Owners, the PJM Transmission Owners (PJM TOs), and the New York Power Authority were currently reviewing billings under the Agreement, and had requested that NYISO cease monthly settlements of amounts related to the Ramapo PARs charged to the PJM TOs while they perform this review.

FERC grants a request for waiver

E-7, *NorthWestern Corporation*, Docket No. TS16-1-000. This order grants NorthWestern's request for a continuation of its Standards of Conduct separation of functions waiver notwithstanding its changed circumstances.

FERC grants a request for waiver

E-8, *City of Rochester, Minnesota Board of Public Utilities*, Docket No. TS15-3-000. The order grants a request by the City of Rochester for waiver of the Standards of Conduct requirements, as applicable to Rochester under the Commission's reciprocity rules, in view of the fact that Rochester meets the definition of a small utility.

FERC grants a request for waiver

E-9, *Alcoa Power Generating Inc*., Docket No. ER16-2437-000. This order grants Alcoa Power Generating's request for waiver of Order No. 1000 requirements for its Tapoco Division, as it meets the "limited and discrete transmission facilities" and "small public utility" standards that justify such waiver.

FERC grants a request for waiver

E-10, *Alcoa Power Generating Inc*., Docket No. ER13-108-001. This order grants Alcoa Power Generating's request for continued waiver of Order No. 1000 requirements for its Long Sault Division, as it meets the "limited and discrete transmission facilities" standard that justifies such waiver.

FERC grants a complaint

E-11, *Goodyear Tire & Rubber Company v. Entergy Texas, Inc*., Docket No. EL16-105-000. The order grants Goodyear's complaint and finds that Entergy Texas may not rely on an earlier Commission order as a basis for terminating its power purchase agreement with Goodyear. In its complaint, Goodyear alleged that Entergy Texas' notice of intent to terminate its power purchase agreement for purchases from Goodyear's qualifying facilities located at Goodyear's Beaumont Chemical Plant in Beaumont, Texas, is contrary to Entergy Texas' obligation to purchase energy and capacity from Goodyear in accordance with the Public Utility Regulatory Policies Act of 1978 and the related regulations, and is inconsistent with the Commission's January 21, 2016 order granting, only in part, Entergy's application to terminate the Entergy Operating Companies' mandatory purchase obligation. The order explains that the Commission's earlier order terminating Entergy Texas' obligation to purchase from qualifying facilities larger than 20 MW was inapplicable here, where the Goodyear facilities were under 20 MW.

FERC approves an uncontested settlement

E-12, *PJM Interconnection, L.L.C. & Northeast Transmission Development, LLC*, Docket Nos. ER16-453-000 & -001. This order approves an uncontested settlement establishing the base return on equity for Northeast Transmission Development, an independent developer participating in the Artificial Island project in the PJM region.

FERC approves an uncontested settlement

E-13, *Pacific Gas and Electric Company*, Docket Nos. ER15-2294-000 and ER15-2294-001. This order approves an uncontested settlement regarding the proposed wholesale and retail transmission revenue requirements in PG&E's Transmission Owner Tariff.

FERC approves an uncontested settlement

E-14, *Midwest Independent Transmission System Operator, Inc., et al.*, Docket Nos. EL02-111-145, EL03-212-140, EL04-135-126, and ER05-6-124. This order approves an uncontested settlement that resolves all issues relating to the Seams Elimination Cost/Charge Adjustment/Assignment charges between Baltimore Gas and Electric Company and the MISO Settling Parties.

FERC approves an uncontested settlement

E-15, *NextEra Energy Transmission West, LLC*, Docket No. ER15-2239-000, *et al.* This order approves the uncontested settlement offer of NextEra Energy Transmission West, LLC (NEET West). The settlement resolves the return on equity (ROE) issue set for hearing and also provides that the base ROE shall not be subject to change for three years after the date on which NEET West's transmission projects are under the operational control of the California Independent System Operator Corporation.

FERC approves a final rule

M-1, *Regulations Implementing the FOIA Improvement Act of 2016 and Clarifying FOIA Regulations*, Docket No. RM17-5-000. This final rule amends 18 C.F.R. § 388.106-10 of the Commission's regulations to implement the new statutory mandates from the Freedom of Information Act Improvement Act of 2016. The rule also amends 18 C.F.R. § 375.309 to delegate authorization to the General Counsel to make determinations in response to FOIA administrative appeals.

FERC denies rehearing

H-2, *Alaska Electric Light and Power, et al.*, Project No. 2307-075, *et al*. The order denies a rehearing request filed by a group of licensees of Alaska hydropower projects

(the Alaska Group) in response to the Executive Director's June 9, 2016 letter denying the Alaska Group's appeal of their 2016 federal land use bills. The order finds that Commission staff properly applied the methodology for calculating charges for use of government lands adopted in an earlier, final Commission order. However, the order notes that the Commission, in response to a petition for rulemaking also filed by the Alaska Group, is inviting comments on a Notice of Inquiry regarding the Commission's current methodology for calculating annual charges for use of government lands for hydropower projects in Alaska.

FERC authorizes non-project use of project land and waters

H-4, *Public Utility District No. 2 of Grant County, Washington,* Project No. 2114-279. The order approves Public Utility District No. 2 of Grant County, Washington's (Grant PUD) application for non-project use authorization to lease 38.5 acres of project lands on Crescent Bar Island to three on-island homeowners associations (HOAs) based on a settlement agreement, which resolved complex, multi-year litigation between Grant PUD and the HOAs seeking to maintain the existing residential areas on the island. The order concludes that the proposed non-project use of project lands and waters, as modified, would be consistent with project purposes and should be approved.

FERC denies rehearing

H-5, *Rivertec Partners, LLC,* Project No. 14754-001. The order denies rehearing of Commission staff's July 1, 2016 order dismissing Rivertec Partners' preliminary permit application for the Lincoln Hydroelectric Project No. 14754, which would be located at the U.S. Army Corps of Engineers' Libby Dam located on the Lake Kootenai River in Lincoln County, Montana. The order affirms staff's finding that the Commission lacks authority to issue a permit for the proposed project.

FERC authorizes certificate amendment

C-1, *Magnum Gas Storage, LLC,* Docket No. CP16-18-000. This order grants Magnum's request to amend its March 17, 2011 certificate of public convenience and necessity by authorizing Magnum to relocate its previously approved natural gas storage caverns and associated surface facilities within the previously analyzed project area and to provide a new firm wheeling transportation service under market-based rates. The order also extends the time by which the facilities must be constructed and placed into service.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Redundant Systems May Not Cold-Start Unless Fully Intact to Prevent Dual Primary Operation

Primary Interest Groups
Balancing Authorities (BAs)
Reliability Coordinators (RCs)
Transmission Operators (TOPs)

Problem Statement
A system failure occurred during routine maintenance of critical IP network infrastructure. Due to redundancy present in the system, no significant service interruption was expected.

Details
An entity's communications within their energy management system (EMS) and to external systems is primarily facilitated by two high-performance Ethernet switches. These switches are designed in a high-availability fashion to protect against service interruption during maintenance or due to hardware failure. During initial commissioning and thereafter during periodic testing in the identical QA/testing system, system operators and systems (sub-second recovery) find it more difficult to detect traffic interruptions.

Following the entity's NERC/CIP patch management procedures, the entity deemed a system patch/update was necessary to ensure the continued reliable operation of the cyber system. The patch was deployed on several noncritical but similar hardware installations throughout the organization in addition to the identical QA/test EMS system. All went as expected with no impact to systems or connectivity.

When the maintenance was scheduled and executed on the production system, a bug was encountered, and part of one switch configuration was corrupted. The corruption was not immediately apparent to engineers performing the maintenance; it would be identified approximately 30 minutes later. When the two switches did not have a consistent configuration, traffic was halted. Engineers were able to verify that the second switch's configuration was intact, and the upgrade process had not yet executed on the second switch. Acting quickly, engineers powered down the freshly upgraded switch and expected traffic to resume normally. It did not.

The switches were power cycled in various orders in an attempt to restore service. Once the corruption/missing configuration was identified, it was restored from backup and system functionality resumed immediately.

It was later determined that the network switches would not forward traffic when the two units did not have a matching configuration. Moreover, it was determined that a single switch would not start without

its mate in a cold-start situation. This is to prevent dual primary operation (split-brain scenario), where two isolated switches each think that they are the only operating switch.

Corrective Actions

The vendor has since modified their recommended configuration baseline to include the ability to cold-start a single switch after a waiting period. This balances dual primary protection (split-brain scenario) with the operational need to start a system using a single network switch.

Engineers now have processes to quickly compare configurations with known good baselines during maintenance operations.

Standard commissioning and testing procedures include cold-starting redundant systems when the mate is not present.

Lesson Learned

- Two-node redundant systems are inherently difficult to operate in certain failure modes. A single system (network, server, application, or otherwise) has no way of determining if it has failed, or its partner has failed in the event that communication is lost between them. “Heartbeat” connections must be of the highest reliability and must employ multiple methods. In a three-node (or more) scenario, a quorum (>50%) of nodes must be healthy and functional to maintain system integrity. These concepts must be understood at all levels of technicians, operators, and engineers of redundant systems.
- In addition to commonly performed failover testing, all aspects of critical system operation must be tested on redundant systems, especially when the system is not fully healthy. Often, a single failure produces several related failures and it is important to understand precisely how critical systems will function under all possible circumstances.
- Backups and disaster recovery procedures necessary to completely recover a piece of hardware or software, with appropriate contingency plans, should be readily available before performing any maintenance, routine or otherwise.

NERC’s goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	MRO – Event Analysis
Source of Lesson Learned:	Midwest Reliability Organization
Lesson Learned #:	20161101

Date Published:	November 1, 2016
Category:	Communications

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

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Lesson Learned

Failover Configuration Leads to Loss of EMS

Primary Interest Groups
Reliability Coordinators (RCs)
Transmission Operators (TOPs)
Balancing Authorities (BAs)

Problem Statement
Configuration settings of an entity's EMS applications and tasks caused unintended automatic failovers to backup EMS servers multiple times in a row. This set up a failover loop, hindering recovery efforts.

Details
When a failover was initiated from EMS-C server (the entity's primary EMS server) to EMS-D server (the entity's designated EMS backup server), the AGC application aborted twice within a minute during EMS-D's initialization/startup. As designed, this then caused an automatic failover to the next backup EMS server in line (EMS-A). The same condition was experienced by EMS-A, which initiated another automatic failover to the next backup EMS server in line (EMS-B). When the system reached the final available server (EMS-B), all systems were in a DISABLED state.

Corrective Actions
In this particular event, the entity removed the scheme that initiated an automatic failover after two consecutive AGC failures (within a minute) from the EMS process manager model. The entity also reviewed all other schemes to ensure that the triggering of an automatic failover is properly defined.

Lesson Learned
Entities should review all failover configuration settings in the EMS that could initiate an automatic failover of the EMS to determine the value of the scheme.

Entities should remove schemes that are not necessary or could lead to a cascading failover scenario and they should evaluate whether to allow these applications to fail in lieu of automatic failovers.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email) FRCC – Event Analysis

Source of Lesson Learned:	Florida Reliability Coordinating Council
Lesson Learned #:	20161102
Date Published:	November 1, 2016
Category:	Communications

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

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Lesson Learned

Loss of ICCP due to Database Sizing Issue

Primary Interest Groups
Reliability Coordinators (RCs)
Transmission Operators (TOPs)
Balancing Authorities (BAs)

Problem Statement
During a network model update, a problem was caused by a combination of the number of points being requested by the state estimator (STE) and the number of points available in ICCP. This problem initiated a failure of ICCP, which resulted in the inability to obtain reliable results from the STE and contingency analysis applications.

Details
A large transmission owner in the Eastern Interconnection is in the process of updating and expanding its STE network model. As part of this long-term project, a significant amount of additional data is being requested from neighboring utilities. As such, a tremendous number of points are being added to the ICCP databases to support the expanded model. The entity's ICCP server is configured to talk to external companies as well as six internal servers. With each link into the ICCP server, an associated database table, called ENTRY, on the ICCP server is dynamically allocated based on the number of points being exchanged.

As part of the model expansion project, additional links were implemented to assist with the development of STE server staging for testing. The number of items in the ENTRY table expands by the following calculation: *(the number of new points) X (the number of links receiving the new points).*

This STE update required an additional 13,000 points from the ICCP. These had already been added to the ICCP database and to the development and staging STE servers. When the production STE server was updated, it began requesting the 13,000 additional points again and the ENTRY table was increased by 26,000 points (13,000 for each of the two production STE servers). This exceeded the maximum allowed size of the ENTRY table and caused the ICCP processes to abort. Further investigation revealed that the ENTRY table was 97% full prior to the expansion, and the extra points caused it to exceed its maximum size.

A failback to the previous ICCP database was attempted, but this did not successfully resolve the issue.

There are multiple ways the issue could have been resolved:

- The ICCP database could have been decreased in size below the threshold.
- The number of points being requested by the STE server could have been reduced.
- The number of links exchanging data with the ICCP server could have been decreased.
- The requests being made could have been accommodated by increasing the size of the ENTRY table.

Corrective Actions

- The database table was temporarily resized to accommodate the appropriate number of entries.
- More extensive research was done to determine the total size that will be needed through the end of the network model expansion project.
- A report was created to compare the current size of database tables to their maximum limit. This is now reviewed at each ICCP database change.
- Two ICCP support staff completed a vendor class on ICCP support and maintenance.

Lesson Learned

- Database sizes need to be carefully monitored as a system is expanded. Sizes should be large enough to accommodate all data being requested, not just what is currently being transferred.
- Primary databases, as well as peripherally associated databases, need to be evaluated for size constraints.
- ICCP databases should be set up so that external companies cannot inadvertently request data that does not originate in the host utility.
- Backup support staff should be fully trained so that discovery of problems does not rest completely with primary support personnel.
- The vendor may need to be contacted to verify that database sizes can be increased without causing problems or to provide a more comprehensive validation routine.
- Support staff should meet regularly to discuss questions, discoveries, and findings.
- Alternative ICCP configurations need to be evaluated to determine if there is a more efficient means to feed data into the staging and development systems.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	Jacquie Smith (via email) or (303) 247-3067
Source of Lesson Learned:	Reliability*First*
Lesson Learned #:	20161103
Date Published:	November 1, 2016
Category:	Communications

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2017 Business Plan and Budget

Draft 2

July 15, 2016

RELIABILITY | ACCOUNTABILITY






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Atlanta, GA 30326
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About NERC

Overview

The North American Electric Reliability Corporation (NERC) is a not-for-profit entity organized under the New Jersey Nonprofit Corporation Act. NERC's mission is to improve and ensure the reliability of the Bulk Power System (BPS)[1] in North America. NERC's area of responsibility spans the continental United States and portions of Canada and Mexico. Entities under NERC's jurisdiction are the users, owners, and operators of the BPS—a system that serves the needs of over 340 million people, includes installed electricity production capacity of approximately 1,200 gigawatts, operates 475,000 miles of high-voltage transmission (100 kV and above), and is comprised of assets worth more than one trillion dollars.

Electric Reliability Organization (ERO)

The Federal Energy Regulatory Commission (FERC or Commission) certifies and has oversight of NERC as the electric reliability organization (ERO) within the United States to establish and enforce reliability standards for the U.S. portion of the BPS, pursuant to Section §215 of the Federal Power Act (§215).[2] As of June 18, 2007, FERC granted NERC the legal authority to enforce reliability standards with all U.S. users, owners, and operators of the BPS and made compliance with those standards mandatory and enforceable. Equivalent relationships have been sought and, for the most part, realized in Canada and Mexico.

International Relations

Prior to adoption of §215 in the United States, the Canadian provinces of Ontario (in 2002) and New Brunswick (in 2004) adopted all NERC reliability standards that were approved by the NERC Board of Trustees (Board) as mandatory and enforceable within their respective jurisdictions through market rules. Reliability legislation is in place, or NERC has memoranda of understanding with, provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, Manitoba, Saskatchewan, British Columbia, and Alberta, and with the National Energy Board of Canada (NEB). NERC's standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. Manitoba has adopted legislation, and standards are also mandatory. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transmission Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC reliability standards are now mandatory in British Columbia and Nova Scotia. NERC and the Northeast Power Coordinating Council (NPCC) have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. NEB has made reliability standards mandatory for international power lines between the U.S. and Canada.

In Mexico, the Comisión Federal de Electricidad has signed the Western Electricity Coordinating Council's (WECC's) reliability management system agreement, which applies only to Baja California Norte.

Membership and Governance

An 11-member Board of Trustees (the Board), comprised of 10 independent trustees and NERC's president and chief executive officer serving as the management trustee, governs NERC. The Board has formed several committees to facilitate oversight of the organization in the areas of finance and audit, governance and human resources, compliance, standards oversight and technology, nominations and, most recently, enterprise-wide risk.

[1] NERC's standards, compliance and enforcement activities are focused on the Bulk Electric System (BES), which is comprised of certain BPS facilities.

[2] ERO Enterprise Strategic Plan

Membership in NERC is open to any person or entity that has an interest in the reliability of the North American BES. Membership is voluntary and affords participants the opportunity to engage in the governance of the organization through election to the Member Representatives Committee (MRC).[3] More than 600 entities and individuals are members of NERC.

Scope of Oversight

As the international, multijurisdictional ERO in North America, NERC is authorized to:

- Propose, support the development of, monitor compliance with, and enforce mandatory reliability standards for the North American BPS, subject to regulatory oversight and approvals from FERC in the United States and applicable authorities in Canada;
- Conduct near-term and long-term reliability assessments of the North American BPS;
- Certify BPS operators as having and maintaining the necessary knowledge and skills to perform their reliability responsibilities;
- Maintain situational awareness of events and conditions that may threaten BPS reliability;
- Coordinate efforts to improve physical security and cybersecurity for the BPS of North America;
- Conduct detailed analyses and investigations of system disturbances and unusual events as well as measure ongoing system trends to determine root causes, uncover lessons learned, and issue relevant findings as advisories, recommendations, guidelines, and essential actions to the industry to mitigate and control risks to reliability; and
- Identify and prioritize risks to reliability and use a broad toolkit to mitigate and control risks to reliability, including the potential need for new or modified reliability standards, improved compliance monitoring and enforcement methods, or other initiatives.

Delegated Authorities

In executing its responsibility, NERC delegates certain authorities to eight regional reliability entities (Regional Entities or the Regions) to perform aspects of the ERO functions described through delegation agreements. FERC has approved delegation agreements between NERC and the eight Regional Entities (Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council, Inc. (NPCC), ReliabilityFirst, SERC Reliability Corporation (SERC), Southwest Power Pool Regional Entity (SPP RE), Texas Reliability Entity, Inc. (Texas RE), and the Western Electricity Coordinating Council (WECC)[4]). These agreements describe the authorities delegated and responsibilities assigned to the Regional Entities in the United States to address, among other things: (1) developing regional reliability standards, (2) monitoring compliance with and enforcement of mandatory reliability standards (both North American-wide and regional), (3) certifying registered entities and registering owners, operators, and users of the BES, (4) assessing reliability and analyzing performance, (5) training and education, (6) event analysis and reliability improvement, and (7) situation awareness and infrastructure security. NERC expects Regional Entities whose territories and geographic footprints extend into Canadian provinces and Mexico to perform equivalent functions in those jurisdictions.

[3] The Member Representatives Committee (MRC) comprises 28 voting representatives elected from the 12 membership sectors. The MRC elects the independent trustees and, along with the Board, votes on amendments to the Bylaws. The MRC also provides policy advice and recommendations to the Board on behalf of stakeholders with respect to annual budgets, business plans, and other matters pertinent to the purpose and operation of the organization.

[4] WECC has sub-delegated its Reliability Coordinator ("RC") function to Peak Reliability, which commenced operations and assumed the RC function within the WECC footprint on January 2, 2014.

ERO Enterprise Operating Model

The collective network of leadership, experience, judgment, skills, and technologies shared among NERC and the eight Regional Entities is referred to as the ERO Enterprise (the Enterprise). In 2014, a common operating model, Improving Coordinated Operations across the ERO Enterprise,[5] was developed to define how NERC and the Regional Entities achieve excellence in the oversight and execution of statutory functions by collaborating to mitigate reliability risks. The model also defines the division of the roles and responsibilities for NERC and the Regional Entities to efficiently and effectively execute services performed as the collective Enterprise. In 2015, implementation of this model progressed with oversight plans developed for Compliance Monitoring and Enforcement programs, and Registration. Further, NERC and the Regional Entities deepened its coordination activities to identify, prioritize and address risks to reliability.

NERC has unique responsibilities within the Enterprise to design the oversight of program areas; develop operational oversight and leadership; set qualifications and expectations for the performance of delegated activities; and assess, train, and give feedback to corresponding regional programs. NERC also reviews and provides input to the annual Regional Entity business plans and budgets, including but not limited to review of resource allocations, staffing capacity assessments, and program performance assessments. NERC input and review occurs before regional board approval.

Similarly, the Regional Entities have a mirrored set of responsibilities that include being responsive to the design of the operational model, providing input into the overall development of each ERO program area, providing training and development to meet ERO qualifications, being receptive to feedback from the ERO, and making responsive adjustments. Regional Entities also have an obligation to meet professional standards of independence and objectivity, and provide the best available expertise for addressing risks.

With due recognition and awareness of the distinction between individual roles, responsibilities, and corporate status, NERC and the Regional Entities are continually refining their individual and collective operating and governance practices in support of an agreed-upon set of strategic goals and objectives that are designed to ensure the ERO fulfills its statutory obligations.

Statutory and Regulatory Background

NERC's authority as the ERO in the United States is based on Section 215 of the Federal Power Act, as added by the Energy Policy Act of 2005,[6] and the Commission's regulations and orders issued pursuant to Section 215. In Canada, NERC's authorities are established by the memoranda of understanding and regulations previously mentioned.

Funding

Section 215 of the Federal Power Act and the Commission's regulations specify procedures for NERC's funding in the United States. NERC's annual business plan and budget is subject to Commission approval in the United States. Once approved, NERC's annual funding is provided through assessments to load-serving entities. These assessments are allocated on a net-energy-for-load (NEL) basis. Equivalent funding mechanisms are provided in Canada, subject to the specific laws and regulations of each province.

The Regional Entities' funding requirements are addressed separately in their respective business plans and budgets, which must be reviewed and approved by NERC and FERC in the United States. Assessments for the Regional Entity budgets are included in the overall NERC assessments to load-serving entities.

[5] Improving Coordinated Operations Across the ERO Enterprise

[6] This was codified in section 215 of the Federal Power Act, 16 United States C. 824o.

Introduction and Executive Summary

TOTAL RESOURCES (in whole dollars)	2017 Budget	U.S.	Canada	Mexico
Statutory FTEs	189.88			
Non-statutory FTEs				
Total FTEs	189.88			
Statutory Expenses	$ 66,921,632			
Non-Statutory Expenses	$ -			
Total Expenses	$ 66,921,632			
Statutory Inc (Dec) in Fixed Assets	$ 2,680,543			
Non-Statutory Inc (Dec) in Fixed Assets	$ -			
Total Inc (Dec) in Fixed Assets	$ 2,680,543			
Statutory Change in Reserves Requirement	$ (69,598)			
Non-Statutory Change in Reserves Requirement				
Total Working Capital Requirement	$ (69,598)			
Proceeds from Financing Activities	$ 19,083			
Total Statutory Funding Requirement	$ 69,551,660			
Total Non-Statutory Funding Requirement	$ -			
Total Funding Requirement	$ 69,551,660			
	TOTAL	**US**	**CANADA**	**MEXICO**
Statutory Funding Assessments	$ 59,856,314	$ 54,326,337	$ 5,353,026	$ 176,951
Non-Statutory Fees				
NEL	4,514,633,135	3,983,687,261	518,227,758	12,718,116
NEL%	100.00%	88.24%	11.48%	0.28%

Strategic Goals and Metrics

The ERO Enterprise strategic plan and framework informed by the following activities completed in 2015: (1) NERC's State of Reliability Report; (2) the Reliability Issues Steering Committee's (RISC's) ERO Reliability Risk Priorities Report and Supplemental Technical Summary, which includes identified risk profiles; and (3) input from the NERC Board and Regional Entity Boards. In 2015, these inputs were used by ERO Enterprise leadership to:

- **Update ERO Enterprise Longer-term Strategic Planning Considerations** – The ERO Enterprise makes any necessary adjustments to its longer-term strategic planning considerations, which takes into consideration Bulk Electric System (BES) reliability issues over a 5 to 15-year planning horizon.
- **Update the Three-year ERO Enterprise Strategic Goals** – The ERO Enterprise makes any necessary adjustments to its strategic goals for the next three years.
- **Develop Annual ERO Enterprise Metrics** – The ERO Enterprise develops annual metrics to measure the ERO Enterprise's progress in attaining the strategic goals.
- **Develop Annual Business Plans and Budgets** – Working collaboratively, NERC and each of the Regional Entities develop annual business plans and budgets (BP&Bs) that reflect the resources necessary to support achievement of the goals set forth in the strategic plan.

Evolving Reliability Risks

Over the past five years, NERC has transformed its activities towards being more risk-based, ensuring that the right activities are focused on the most pertinent risks to the reliable operation of the bulk power system. The RISC is an advisory committee to the Board, providing key insights, priorities, and high-level leadership for issues of strategic importance to BPS reliability. The 2015 RISC report presents the results of their continued work to define and prioritize risks, and offer recommendations to the Board to inform the development of NERC's risk strategy. The report recommendations are considered as the Strategic Plan, Goals and supporting activities are updated for the coming years. In 2015, the RISC recommended a high level of focus and priority in the following areas:

- **Regulatory Uncertainty (Markets, states, and federal/provincial)**
  These risks arise where the impacts from regulatory initiatives are uncertain in their extent, timing, and potential reliability considerations. These uncertainties are accentuated by the interplay among these three arenas, each of which reflects policy, regulatory, and legislative dimensions which may not include sufficient reliability coordination.

- **Resources (Changing resource mix, inadequate planning coordination, and ineffective resource planning)**
  This set of evolving risks reflects interdependent aspects from the continued and accelerated rapid transformation of the resource mix. As part of the increased and accelerated integration of new types of variable, renewable, and distributed energy resources, planners must ensure that sufficient ERSs and operator flexibility are available to maintain reliability.

- **Resiliency: Cyber security**
  These risks reflect aspects of resilience related to potential cyber disruptions of the BPS. As cyber aspects evolve, they require more assertive and flexible approaches to provide adequate assurances of reliability.

2016-2019 Strategic Goals

The ERO Enterprise has five strategic goals, adopted by the NERC Board in November 2015, enabling it to successfully carry out its mission as further described in the Strategic Plan. For each goal, a detailed description is provided, activities that contribute to its success, and additional information about the allocation of NERC's resources toward their achievement are noted below. The associated metrics in support of these goals have been approved for 2016[7]; updated strategic goals and associated metrics will be finalized later in 2016 for the 2017 year, with opportunities for stakeholder feedback prior to their approval. At this time it is not anticipated that these updates will have a material impact on NERC's overall budget or resource allocation among operating areas for 2017. However, the updates may potentially affect priorities and workload within particular departments and will inform resource planning and allocation for the 2018 budget year.

Goal 1
Timely and Risk-Responsive Reliability Standards

Reliability standards establish threshold requirements for assuring the BES is planned, operated, and maintained to minimize risks of cascading failures, avoid damage to major equipment, or limit interruptions of bulk electric supply. Reliability standards are clear, timely, responsive to reliability risks and cost-effective.

Contributing Activities

- Conduct periodic reviews and assessment of whether the reliability standard is properly structured for emerging risks.
- Assess reliability standards compared to the BES risk profile; address the most important unmitigated risks, including applicable high-impact, low-frequency risks.
- Develop and implement ERO Enterprise feedback loops to identify and address gaps or ambiguities in reliability standards, including the evaluation of significant BES events (including all category 3 and above).
- Develop and implement procedures for assessing the cost impact of reliability standards.

Goal 2
Objective and Risk-informed Compliance Monitoring, Enforcement, and Organization Certification and Registration

The ERO Enterprise is a strong enforcement authority that is independent, without conflict of interest, objective, and fair, and promotes a culture of reliability excellence through risk-informed compliance monitoring, enforcement, certification, and registration.

Contributing Activities

- Consistently register and deregister entities based on risk to the BES and the BES definition.
- Evaluate the certification program for effectiveness and implement consistently across the ERO Enterprise.
- Develop Compliance Oversight Plans for registered entities that address the relevant risks.
- Focus Compliance Monitoring and Enforcement activities on the most significant risks to the BES.
- Process non-compliance using the appropriate method, considering the risk to the BES.

[7] See 2016 ERO Enterprise and Corporate Metrics for details.

- Implement Compliance Monitoring and Enforcement consistently, timely, and transparently to industry.

Goal 3
Identification and Mitigation of Significant Current Risks to Reliability

The ERO Enterprise identifies the most significant risks to reliability, provides assurance for mitigating reliability risks, and promotes a culture of reliability excellence. The ERO Enterprise supports the Electricity Information Sharing and Analysis Center (E-ISAC), the Cybersecurity Risk Information Sharing Program (CRISP), reliability assessments, situational awareness, and physical security and cybersecurity preparedness.

Contributing Activities

- Perform reliability data-grounded analyses and sustain independent, technical assessments of proposed regulatory rules or proposed statutes (state, provincial, or federal) as well as significant market rules to determine potential impacts to reliability.
- Maintain a BES risk profile to prioritize and rank reliability risks.
- Develop project plans and business case assessments for high-priority risks including cost and practicality of assessment; implement or facilitate initiatives to address high-priority risks.
- Integrate risk data sources, such as event analysis, Transmission Availability Data System, Generating Availability Data System, and relay misoperations as well as other occurrences (e.g., AC equipment failures) to provide lessons learned, recommendations, identified risks, and their mitigation to promote reliability.
- Analyze system performance and significant events (e.g., sampling of Category 2 events in addition to assessing all Category 3 and above) to identify gaps in reliability standards, compliance effectiveness, registration, and risk controls effectiveness, as well as the development of lessons learned or other information sharing activities that promote BES reliability.
- Enhance communications among the E-ISAC, the Telecommunications Information Sharing and Analysis Center, and Natural Gas Information Sharing and Analysis Center.
- Facilitate the availability, sharing and value of physical security and cybersecurity threat and vulnerability information, analytics, and analysis.

Goal 4
Identification and Assessment of Emerging Risks to Reliability

The ERO Enterprise identifies, evaluates, studies and independently assesses emerging risks to reliability.

Contributing Activities

- Develop sufficiency/adequacy guidelines for essential reliability services (ERS) including emerging risks. Include consideration of the range of reliability attributes based on a diverse resource mix and load behavior, such as ramping, fast regulation, reserve services, and interdependent sector performance.
- Enhance reliability assessments to reflect changing resource mix behavior, including distributed energy resources and ERS, with probabilistic approaches, considering the variable and energy-limited nature of the resource shifts.
- Evaluate the impacts on BES recovery and restoration plans including consideration of distributed resources.

Goal 5
Effective, Efficient, and Collaborative ERO Enterprise

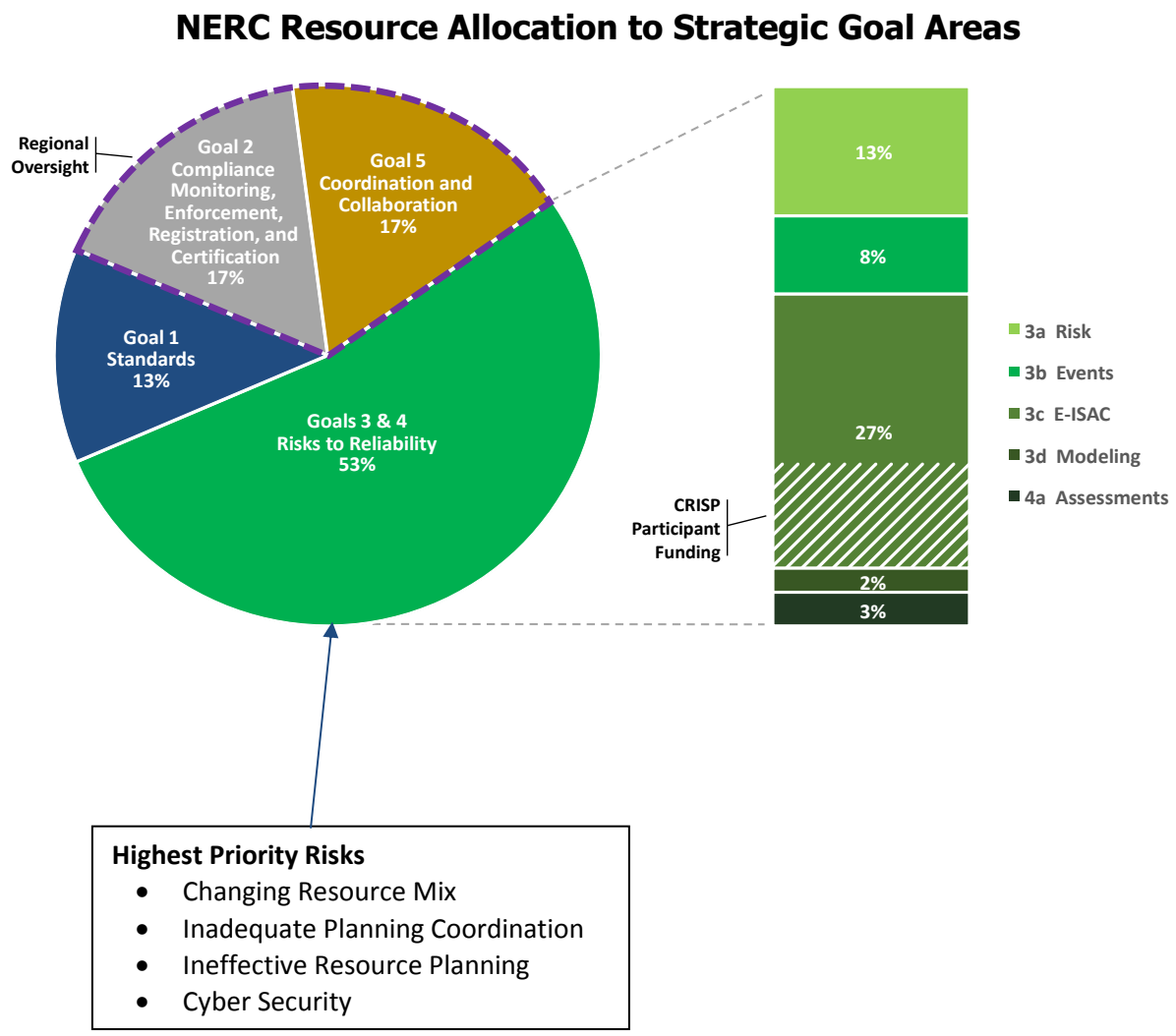
The ERO Enterprise improves transparency, consistency, quality, efficiencies, cost-effectiveness, and timeliness of results and operates as a collaborative enterprise.

Contributing Activities

- Articulate a shared vision of reliability excellence and support and inspire stakeholders continent-wide, including in international jurisdictions, in working to attain that vision.
- Engage the support and expertise of stakeholders in prioritizing and resourcing reliability initiatives.
- Communicate expectations clearly and foster collaboration to deliver important results in advancing system reliability.
- Acquire, engage, and retain highly qualified talent with requisite technical expertise to execute the ERO Enterprise's statutory functions.
- Understand and manage ERO Enterprise internal risks.
- Processes and procedures are consistent, effective, and efficient.
- Clearly delineate ERO Enterprise roles and responsibilities using the ERO Enterprise Operating Model to mature the collaborative processes.

Allocation of NERC Resources to Strategic Goals and Risk Priorities

The charts below provide an overview of the allocation of NERC's 2017 resources associated with each strategic goal, as well as the RISC priorities. Using FTEs and funding as a guide, the charts reflect the relative amount of total NERC resources (people and dollars) focused on supporting each of the five strategic goals noted above. Obviously many NERC departments work on multiple activities that further multiple goals, and precision in forecasting all activities supporting each goal is not practical. However, these charts provide a general picture regarding how the company's resources are allocated.



Ongoing Focus on Cost Control and Efficiency

NERC and the Regional Entities continue to work collaboratively to improve efficiency, evaluate resources, and leverage combined skillsets to improve various ERO Enterprise activities and control costs. This collaboration and the resulting efficiencies can be found in a number of areas, including but not limited to:

- **ERO Enterprise IT Investments:** NERC and the Regional Entities, working collaboratively with oversight of NERC's Standards Oversight and Technology Committee, have developed a long-term enterprise information technology program resulting in a number of enterprise tools. The goals is to enhance operations and reduce costs at the regional and registered entity level. For example, enterprise tools have helped and will further facilitate efficiency of registration and data submittals, improved consistency in registered entity resources devoted to compliance, and improved overall reliability through information sharing on Events Analysis and Situation Awareness.
- **Enforcement**: NERC has worked closely with Regional Entities to streamline enforcement staff in connection with the development of more efficient and risk-based enforcement mechanisms.
- **Standards:** As standards development has matured, NERC management has reduced standards staff allocations towards more critical activities like cyber security and analytical capabilities.
- **Legal:** As a result of the aforementioned efficiencies and the maturity of NERC's and ERO Enterprise's business processes, the legal department has reduced its resource requirements, reallocating limited resources to more critical priorities without impacting the company's overall staffing requirements.
- **Forums**: As further described in the quarterly forum reports to the NERC Board of Trustees, NERC and the Regional Entities continue to leverage the transmission and generation forums to jointly address risks to reliability to mitigate their impacts on the reliable operation of the BES.
- **Industry:** The Enterprise continues to collaborate with, and rely on, industry resources and expertise through the various standing committees[8], working groups and task forces which are critical to both identifying and supporting key initiatives and priorities.

2017 Key Business Planning Assumptions

As part of the annual business planning process, NERC and the Regional Entities developed a set of common business planning assumptions supporting the development their respective business plans and budgets. The Regional Entities used these assumptions to evaluate their projected workloads and determine resource levels and allocation required to complete necessary tasks and meet the obligations of their Regional Delegation Agreements. These common business planning assumptions are set forth in Exhibit A.

Application of Section 215 Criteria

In its order approving NERC's *2013 Business Plan and Budget*, FERC required NERC to establish criteria for determining whether its proposed activities are eligible for funding under Section 215. In an order dated April 19, 2013, FERC approved NERC's proposed criteria, with certain modifications.[9] Exhibit B summarizes the major activities NERC proposes to undertake in 2017 and the approved Section 215 criteria applicable to such activities.

[8] For further information please see the quarterly reports to the NERC Board of Trustees by the NERC Operating, Planning, Critical Information Protection, Standards and Compliance Certification Committees.

[9] North American Electric Reliability Corporation, Order on Compliance, 143 FERC ¶ 61,052 (2013).

Overview of 2017 Budget and Funding Requirements

NERC's 2017 combined expense and fixed asset (capital) budget is approximately $69.6M, which represents an increase of approximately $2.4M (3.6%) from the 2016 budget. Total expenses are increasing approximately $1.0M (1.5%) over 2016. The total fixed asset (capital) budget, excluding depreciation,[10] is approximately $4.4M, an increase of $461k over 2016. Approximately $8.3M (11.9%) of NERC's 2017 budget is related to CRISP. In the absence of CRISP, the 2017 budget would also increase $2.1M (3.5%) over 2016. As further explained in Section A – Electricity Information Sharing and Analysis Center (E-ISAC), the majority of the NERC CRISP budget will be funded by participating utilities, with only a small portion funded through assessments. A comparative statement of activities presenting NERC's 2017 budget with and without CRISP is set forth later in this section.

Without the release of funds from the Assessment Stabilization Reserve to offset assessments (as discussed below), NERC's total average assessments would increase $3.9M (6.8%) over 2016. One of the primary differences between NERC's current 2017 budget increase of 3.6% and the 6.8% 2017 assessment increase (unadjusted) results from eliminating the one-time application of 2016 penalty funds used to offset U.S. assessments in 2017. This loss of penalty offsets will not impact Canadian or Mexican assessments since U.S. penalty funds are only used to reduce U.S. assessments.[11] Other factors contributing to this difference include debt assumptions and projected reserve requirements, all of which impact assessments in the United States, Canada, and Mexico.

As a long-term strategy to stabilize assessments and align budget and assessment increases more closely, NERC has undertaken a multi-year strategy to manage assessment increases. Under the previous policy for releasing penalty funds, NERC was required to recognize those penalties in subsequent budget periods to offset assessment billings. In February 2015, NERC's Board approved an amendment to the company's Working Capital and Operating Reserve Policy. [12] Among the approved changes to this policy was the creation of an Assessment Stabilization Reserve.[13] This reserve was established to address the strategic goal of more closely aligning budget and assessment increases and provide resources to better manage year-to-year assessment increases. The eventual goal is to narrow the gap between annual percentage changes in NERC's budget and assessments that results from year-to-year changes in penalty collections.

Management proposes an overall average 2017 assessment increase of 4.9%, which includes the release of $1.1M from the Assessment Stabilization Reserves to offset U.S. assessments. The allocation of assessments to Canadian entities will depend on the final determination and allocation of certain compliance and enforcement costs to Canadian entities pursuant to NERC's policy on the allocation of compliance costs.[14]

[10] NERC and the Regional Entities budget Depreciation as an Operating Expense with an equal and offsetting credit against budgeted Fixed Asset Additions; as a result, the budgets do not include depreciation in the funding requirements.

[11] Accounting, Financial Statement and Budgetary Treatment of Penalties Imposed and Received for Violations of reliability standards, December 8, 2008 and as amended August 15, 2013

[12] NERC's Working Capital and Operating Reserve Policy. NERC filed a petition with FERC on March 6, 2015 for approval of this policy; the Commission conditionally approved the revised policy in an order issued June 18, 2015, in Docket No. RR15-8-000. *North American Electric Reliability Corporation, Order Conditionally Accepting Revisions to Working Capital and Operating Reserve Policy*, 151 FERC ¶ 61,225 (2015)

[13] In accordance with the approved policy, this reserve may be funded with penalty funds and surplus operating reserves. The actual amount of the contribution, as well as releases from the fund to reduce assessments, is determined annually as part of NERC's business plan and budget process, including the recommendation by the Board's Finance and Audit Committee and both Board and FERC approval.

[14] Expanded Policy on allocation of Certain Compliance and Enforcement Costs, July 29, 2008.

The following table provides a high-level year-over-year comparison of the major categories of expenses, total budget, and FTEs.

Statement of Activities and Fixed Assets Expenditures 2016 and 2017 Budgets
STATUTORY

	2016 Budget	2016 Projection	Projection v 2016 Budget Over(Under)	2017 Budget	2017 Budget v 2016 Budget Over (Under)	% Over (Under)
Funding						
NERC Assessments	$ 57,081,445	$ 57,081,445	$ (0)	$ 59,856,314	$ 2,774,868	4.9%
Penalty Sanctions	1,439,000	1,439,000	-	1,100,000	(339,000)	
Third-Party Funding (CRISP)	6,830,738	7,335,757	505,019	6,990,447	159,709	
Testing Fees	1,867,972	1,867,972	-	1,921,900	53,928	
Services & Software	50,000	50,000	-	50,000	-	
Workshops	230,000	269,201	39,201	230,000	-	
Interest	3,000	35,898	32,898	3,000	-	
Total Funding (A)	**$ 67,502,155**	**$ 68,079,475**	**$ 577,320**	**$ 70,151,660**	**$ 2,649,505**	**3.9%**
Expenses						
Personnel Expenses	$ 37,283,807	$ 37,288,967	$ 5,161	$ 38,641,331	$ 1,357,525	3.6%
Meeting Expenses	3,620,286	3,646,564	26,278	3,372,886	(247,400)	-6.8%
Operating Expenses	24,903,515	25,947,939	1,044,424	24,800,690	(102,825)	-0.4%
Other Non-Operating Expenses	110,000	100,668	(9,332)	106,725	(3,275)	-3.0%
Total Expenses	**$ 65,917,608**	**$ 66,984,139**	**$ 1,066,531**	**$ 66,921,632**	**$ 1,004,024**	**1.5%**
Fixed Assets						
Depreciation	$ (2,641,943)	$ (2,558,606)	$ 83,336	$ (1,691,457)	$ 950,486	
Computer & Software CapEx	2,447,000	2,362,402	(84,598)	2,572,000	125,000	
Equipment CapEx	1,464,000	1,545,797	81,797	1,800,000	336,000	
Inc(Dec) in Fixed Assets	**1,269,057**	**1,349,593**	**80,535**	**2,680,543**	**1,411,486**	
TOTAL BUDGET	**$ 67,186,665**	**$ 68,333,732**	**$ 1,147,067**	**$ 69,602,175**	**$ 2,415,510**	**3.6%**
FTEs	**192.5**	**188.6**	**(3.9)**	**189.9**	**(2.6)**	**-1.3%**

NERC's 2017 budget and funding requirements reflect the resources necessary to support achievement of the goals and objectives set forth in the Strategic Plan. The 2017 budget is comprised of both operating and capital (fixed asset) costs. Operating costs generally include personnel, consulting, office space, software licensing, third-party data management, and communications and other customary services to support office operations. Fixed asset (capital) costs primarily reflect investments in equipment and software to support operations, including investments in the development of software applications and infrastructure to facilitate improved business processes and efficiency.

Key Budget Assumptions

Key assumptions used in the development of NERC's 2017 budget include the following:

- Maintaining FTEs at a similar level as 2016. Management routinely reviews resource allocation to ensure that the appropriate amount and type of resources are being dedicated to key priorities and activities. As operations in some areas become more efficient and/or major initiatives are completed, resources are redeployed to priority areas. For example, as work on reliability standards reduced as regulatory obligations were addressed, it was possible to reallocate some of those resources to support additional compliance assurance, reliability risk assessment, and security needs without increasing the company's overall FTE budget.
- Applying a 6.0% reduction to FTEs (vacancy rate) to account for attrition and hiring delays. This assumption is based on a review and analysis of historic attrition and vacancy rates, as well as the time it takes to recruit and onboard new staff. This is reduction in the historical vacancy rate

assumptions and reflects the ongoing management focus on recruiting and retaining appropriate resources.

- Market-based compensation for personnel. Executive and staff compensation and benefits are established based on guidelines established by NERC's Corporate Governance and Human Resources Committee and comprehensive market compensation and benefit information provided by a leading nationally recognized compensation and benefits consulting firm, as well as other available data. An updated market study was completed in late 2015 under the oversight of NERC's Corporate Governance and Human Resources Committee.
- Anticipating market increases in medical and dental benefit plan costs. Medical and dental premium cost estimates are based on market data provided by the company's benefits consultant. Current 2017 budget estimates are in the upper end of the range provided by NERC's benefits consultant. This estimate will continue to be evaluated prior to finalization of the final recommended 2017 budget. No other changes to retirement or other benefit plans have been assumed for 2017.
- In 2015, the Electricity Subsector Coordinating Council (ESCC)[15] presented its recommendations resulting from a review of the E-ISAC operations performed that year. These recommendations included a request to evaluate and potentially enhance the user interface and underlying functionality of the E-ISAC portal. In 2015, the ESCC established a Member Executive Committee (MEC) to provide guidance with respect to various E-ISAC matters, including improvements to the E-ISAC portal. As part of an approved 2016 work plan, the E-ISAC staff worked closely with the MEC to develop a business case and funding estimates for these improvements. A power point presentation summarizing the business case, funding estimate and additional detail regarding the portal improvement project is attached as Exhibit F.

  The 2017 E-ISAC budget includes $1M for the portal enhancements ($250,000 of which is allocated to CRISP) for the portal project. The annual impact of the proposed $1M investment on assessments will be approximately $250,000 since projects of this nature are typically financed through NERC's capital financing program and funded over a three year period. The MEC has provided written comments [found here] in support of this investment.
- Meeting and travel expenses are being held flat based on a review of 2015 and 2016 costs. The company has undertaken a number of significant efforts over the past several years to reduce travel and meeting expenses. For example, the company has also worked closely with Regional Entities to share meeting space where possible, which has helped reduce meeting costs.
- Contractor and consulting expenses are developed on a department-by-department basis and reflect both known and anticipated expenses, based on historic and current information.

[15] The Electricity Subsector Coordinating Council (ESCC) serves as the principal liaison between the federal government and the electric power sector, with the mission of coordinating efforts to prepare for, and respond to, national-level disasters or threats to critical infrastructure. The ESCC includes utility CEOs and trade association leaders representing all segments of the industry. Its counterparts include senior Administration officials from the White House, relevant Cabinet agencies, federal law enforcement, and national security organizations.

The following table summarizes total year-over-year contractor and consulting costs by department.

Consultants & Contracts	2016 BUDGET	2017 BUDGET	2017 vs 2016 Budget
Compliance Assurance	200,000	50,000	(150,000)
Event Analysis	56,000	-	(56,000)
Compliance Investigation, Registration and Certification	50,000	-	(50,000)
Reliability Assessments and System Analysis	575,000	525,000	(50,000)
Performance Analysis	509,039	528,082	19,044
Situation Awareness	1,211,475	1,295,850	84,375
E-ISAC	748,335	899,835	151,500
CRISP	5,888,594	5,888,594	-
System Operator Certification	327,600	219,800	(107,800)
Continuing Education, Training & Education	348,200	360,800	12,600
General & Administrative	95,000	15,000	(80,000)
Information Technology	2,094,671	2,312,787	218,116
Human Resources	550,000	575,000	25,000
Finance and Accounting	297,000	457,000	160,000
TOTAL CONSULTANTS AND CONTRACTS	**12,950,914**	**13,127,749**	**176,835**

The Compliance Assurance department will require ongoing, though significantly reduced, consulting support for implementation of compliance assurance reform initiatives. Contract and consulting expenses for the Reliability Assessment, Performance Analysis, and System Analysis are largely for software and services supporting reliability data management and analysis. Situation Awareness costs are primarily related to licenses and services supporting Situation Awareness for FERC, NERC, and the Regional Entities (SAFNR), and other reliability information and notification (e.g., alerts) systems.

E-ISAC consulting costs for 2017 include support for GridEx and analytical tools. Approximately $6M of the total E-ISAC contract and consulting costs are CRISP related and funded by CRISP participants.

Training, Education, and Operator Certification contract and consulting costs include the cost of operator certification, training, and continuing education programs, and training NERC personnel. It also includes supporting compliance and enforcement (risk-based CMEP) and other training initiatives.

Information Technology (IT) contract and consulting support is primarily for systems and software maintenance and support services, including costs for enhancements to and maintenance of enterprise applications. Costs associated with IT security programs and the ongoing implementation and support of a document management program are also included. Software development costs are primarily budgeted under fixed (capital) assets and are discussed further below.

Human Resources contract and consulting costs are primarily for employee training, various surveys, compensation studies, and consulting services to support improvements in human resource information systems.

Finance and Accounting costs are primarily for audit and consulting services to support the Enterprise Risk Management and Internal Control audit plan and Compliance and Certification Committee (CCC) audit plan, as well as consulting services to implement new financial reporting tools and review insurance strategy and solutions.

Fixed Asset (Capital) Budget and Capital Financing

NERC's 2017 capital budget is approximately $4.4M (excluding depreciation), which represents an increase of approximately $461k from 2016. The table below provides a summary of the major capital budget components.

NERC CAPITAL BUDGET	2016	2017
ERO Application Development	$ 1,500,000	$ 700,000
E-ISAC Portal Development		1,000,000
Document Management	465,000	335,000
Hardware (Storage, servers, laptops)	955,000	991,000
Other Equipment	535,000	885,000
Disaster Recovery	200,000	150,000
NERC Software licenses	256,000	311,000
Total Capital Budget	**$ 3,911,000**	**$ 4,372,000**

NERC has budgeted $2.2M (both operating and capital expenses) in 2017 for services related to the planning, design, and implementation of software applications supporting the development of enterprise tools for common NERC and Regional Entity operations. These ERO Enterprise related costs include $700k in capital expenditures and $1.5M in other IT operating costs. Senior management from both NERC and the Regional Entities refined and updated the ERO Enterprise's long-term IT architecture and data management plans and the specific applications that will be under development in 2017. The IT department section offers further detail regarding updates to the Enterprise IT Strategy; the current status of the development of Enterprise IT applications; and projects that will be under development in 2017. Information regarding the cost and benefits of each project are also provided. The proposed $2.2M budget for 2017 related to enterprise application development and support is less than the 2017 projection presented in NERC's *2016 Business Plan and Budget* due largely to the decision to delay the development of a replacement for the current compliance monitoring and enforcement tracking system to 2018. Further information regarding the ERO Enterprise application development plan and budget is contained in Section A – Information Technology department. NERC's 2017 capital budget also includes ongoing funding for IT security, disaster recovery, data storage, replacement of servers and laptops, and software license costs.

The 2017 budget projection assumes that approximately $1.5M of the total $4.4M capital budget will be financed through the capital financing program that was described and put in place as part of NERC's *2014 Business Plan and Budget*. Further information regarding capital financing may be found in Exhibit D.

Working Capital and Operating Reserves

Management is proposing an overall reserve budget of $7.8M for the combined four categories of operating reserves and the Assessment Stabilization Reserve under the company's Working Capital and Operating Reserve Policy. This represents a decrease of $1.1M (11.9%) from the total reserve amounts included in NERC's approved 2016 budget. While individual categories reflect increases and decreases resulting from operating needs and uses, the budget does not reflect additional working capital requirements in total. Pursuant to the company's Working Capital and Operating Reserve policy, funds reserved for future liabilities are now budgeted under a separate reserve category entitled Future Obligation Reserve. This reserve is primarily comprised of existing funds and is budgeted to be $2.6M for 2017. The second category of operating reserves is the System Operating Certification Reserve. The 2017 System Operator Certification Reserve is budgeted at $714k and comprised of existing funds. The third category of operating reserves is the CRISP Operating Reserve, which represents funds dedicated to support CRISP. Similar to 2016, these reserves are established pursuant to a CRISP budget agreed to and funded entirely by utilities participating in CRISP. These reserves have no impact on assessments and they are segregated from other reserves pursuant to the terms of the CRISP agreements. Currently, the CRISP reserves are projected to be $500k in the 2017 budget.

The fourth category of operating reserves is the Operating Contingency Reserve. This reserve includes funds for expenditures that were not anticipated at the time the company's budget was prepared or for which the timing was uncertain. NERC's current policy on Operating Contingency Reserves requires a reserve target of 3.5–7.0%, except as otherwise approved by the Board after review and recommendation by the NERC Finance and Audit Committee. This percentage is calculated against NERC's total budget for operating and capital expenditures, less those costs related to CRISP and System Operator Certification (both having separate reserve categories). For this draft of the 2017 budget, management is recommending an Operating Contingency Reserve of approximately $2.2M, or 3.7% of total operating and capital costs, excluding CRISP and System Operator costs, which is slightly less than the minimum recommended in the policy but within the discretion of the NERC Board of Trustees to approve, upon review and recommendation of NERC's Finance and Audit Committee.

In addition to the four categories of operating reserves and as previously discussed, the company's amended Working Capital and Operating Reserve Policy also provides for an Assessment Stabilization Reserve. To date, this reserve has been funded entirely by previously received penalties and is projected to have a balance of $2.7M as of January 1, 2017, pending approval by the NERC Board. For purposes of the company's *2017 Business Plan and Budget*, management proposes the release of $1.1M in Assessment Stabilization Reserve funds to offset assessments. The use of $1.1M to offset assessments in 2017 yields an average increase of 4.9% over the 2016 assessments. The balance of $1.7M will be used to reduce assessments in a future period, subject to review and approval of the applicable year business plan and budget. A further discussion of the use of this remaining Assessment Stabilization Reserve balance may be found below in the section entitled 2018-2019 Projections.

Department Budget and FTE Comparisons

The following tables set forth a 2016–2017 total budget comparison by department. The amounts shown below reflect all direct and indirect departmental costs, including fixed asset costs. Costs incurred for general and administrative and other overheads are considered indirect, and are allocated to the statutory departments based on the ratio of that department's budgeted FTEs to total budgeted FTEs.

2016–2017 Total Budget by Department

Total Budget	Budget 2016	Budget 2017	Change 2017 Budget v 2016 Budget	% Change
Reliability Standards	8,193,116	8,100,282	(92,834)	-1.1%
Compliance Analysis, Certificaton and Registration	4,632,871	3,646,289	(986,582)	-21.3%
Compliance Assurance	9,420,903	7,858,599	(1,562,305)	-16.6%
Compliance Enforcement	5,293,298	5,800,647	507,349	9.6%
Reliability Assessments and Performance Analysis	9,918,728	12,444,449	2,525,721	25.5%
Training, Education and Operator Certification	3,912,231	3,757,501	(154,731)	-4.0%
Reliability Risk Management				
Event Analysis	5,355,795	5,446,206	90,411	1.7%
Situation Awareness	3,692,197	4,032,862	340,664	9.2%
E-ISAC	16,767,525	18,515,341	1,747,816	10.4%
Total Budget	67,186,665	69,602,175	2,415,510	3.6%
Total Funding	67,502,155	70,151,660	2,649,505	3.9%
Change in Working Capital	315,490	549,485	233,995	0.3%

The decreases in Compliance Analysis, Certification and Registration, and Compliance Assurance departments costs are primarily due to the transfer of resources from these departments as part of the internal reorganization to better align resources to support strategic goals and risk priorities. The increase in the Reliability Assessment and Performance Analysis program area and Event Analysis department budget are due to the reallocation of resources to that department to further support increased reliability risk assessment and analysis resource priorities. The increase in the Situation Awareness department is primarily due to enhancement or modification of reliability-related situation awareness and monitoring tools. The increase in the E-ISAC department is primarily due to planned enhancements to the E-ISAC portal and 2017 GridEx.

The following table presents a year-over-year comparison of FTEs by department and reflects 2016 personnel additions, interdepartmental transfers, and attrition assumptions. An FTE represents the number of employees employed full time during the year, plus the number of employees employed part time (less than full schedule) or during a portion of the year converted to a full-time basis. Headcount represents the total number of personnel employed during the year, regardless of the length of their employment during that year. FTEs will be less than headcount, unless there are no part-time employees or employees who are employed less than a full year. The company's 2017 personnel budget is based upon existing headcount and associated compensation and benefit costs, as well as assumptions on the number and cost of new hires, all within an overall FTE budget. An average vacancy rate is applied to each position and its associated costs to arrive at an overall personnel cost budget. The vacancy rate represents an adjustment, which is applied in the calculation of budgeted personnel costs to account for attrition and variations in the budget assumptions on the timing of new hires.

2016–2017 Year-Over-Year Comparison of FTEs by Department

Total FTE's by Program Area	Budget 2016	Budget 2017	Change from 2016 Budget
STATUTORY			
Operational Programs			
Reliability Standards	17.98	17.16	(0.8)
Compliance Analysis, Certification and Registration	10.14	7.52	(2.6)
Compliance Assurance	19.36	15.51	(3.9)
Compliance Enforcement	12.22	13.16	0.9
Reliability Assessments and Performance Analysis	18.67	23.50	4.8
Training, Education and Operator Certification	7.38	7.05	(0.3)
Event Analysis	11.06	11.28	0.2
Situation Awareness	5.53	5.64	0.1
E-ISAC	18.90	19.74	0.8
Total FTEs Operational Programs	**121.24**	**120.56**	**(0.7)**
Administrative Programs			
General & Administrative	17.52	16.92	(0.6)
Legal and Regulatory	12.22	11.28	(0.9)
Information Technology	22.13	23.27	1.1
Human Resources	2.77	2.82	0.0
Finance and Accounting	16.60	15.04	(1.6)
Total FTEs Administrative Programs	**71.23**	**69.33**	**(1.9)**
Total FTEs	**192.47**	**189.88**	**(2.5)**

*Reflects 2017 additions and transfers between departments, anticipated timing of 2017 hires, and assumes 6% attrition in all programs

Total FTEs in the Administrative Programs is decreasing 2.7%, reflecting reallocation of resources among the various departments The increase in Information Technology FTEs is due to the reallocation of personnel to strengthen project management oversight over NERC and ERO Enterprise software application development and implementation.

The NERC 2017 organizational chart can be found in Appendix 1**.** The difference between the number of positions reflected in the 2017 organizational chart and total 2017 budgeted FTEs is due to assumptions regarding vacancy rates and timing of new hires.

The following pages include a statement of activities comparing the 2016 budget and the proposed 2017 budget, followed by a statement of activities comparing the 2016 budget and the proposed 2017 budget with and without CRISP.

Statement of Activities and Fixed Assets Expenditures 2016 and 2017 Budgets

STATUTORY

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	% Inc 2017 over 2016	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding								
ERO Funding								
NERC Assessments	$ 57,081,445	$ 57,081,445	$ (0)	$ 59,856,314	$ 2,774,868	**4.9%**	$ 59,652,362	$ 203,952
Penalty Sanctions	1,439,000	1,439,000	-	1,100,000	(339,000)		1,100,000	-
Total NERC Funding	**$ 58,520,445**	**$ 58,520,445**	**$ (0)**	**$ 60,956,314**	**$ 2,435,868**		**$ 60,752,362**	**$ 203,952**
Third-Party Funding (CRISP)	6,830,738	7,335,757	505,019	6,990,447	159,709		6,910,701	79,746
Testing Fees	1,867,972	1,867,972	-	1,921,900	53,928		1,921,900	-
Services & Software	50,000	50,000	-	50,000	-		50,000	-
Workshops	230,000	269,201	39,201	230,000	-		230,000	-
Interest	3,000	35,898	32,898	3,000	-		3,000	-
Miscellaneous	-	202	202	-	-		-	-
Total Funding (A)	**$ 67,502,155**	**$ 68,079,475**	**$ 577,320**	**$ 70,151,660**	**$ 2,649,505**	**3.9%**	**$ 69,867,962**	**$ 283,698**
Expenses								
Personnel Expenses								
Salaries	$ 28,842,336	$ 29,052,918	$ 210,581	$ 30,073,438	$ 1,231,102		$ 29,979,980	93,458
Payroll Taxes	1,871,367	1,830,724	(40,643)	$ 1,847,130	(24,237)		1,908,285	(61,154)
Benefits	3,579,280	3,390,190	(189,090)	$ 3,643,806	64,526		3,668,103	(24,297)
Retirement Costs	2,990,823	3,015,135	24,312	$ 3,076,956	86,134		3,127,490	(50,533)
Total Personnel Expenses	**$ 37,283,807**	**$ 37,288,967**	**$ 5,161**	**$ 38,641,331**	**$ 1,357,525**	**3.6%**	**$ 38,683,857**	**(42,526)**
Meeting Expenses								
Meetings	$ 1,096,500	$ 1,194,500	$ 98,000	$ 1,071,500	$ (25,000)		$ 1,071,500	-
Travel	2,203,786	2,190,184	(13,602)	2,203,786	(0)		2,203,786	-
Conference Calls	320,000	261,880	(58,120)	97,600	(222,400)		97,600	-
Total Meeting Expenses	**$ 3,620,286**	**$ 3,646,564**	**$ 26,278**	**$ 3,372,886**	**$ (247,400)**	**-6.8%**	**$ 3,372,886**	**-**
Operating Expenses								
Consultants & Contracts	$ 12,865,914	$ 13,972,958	$ 1,107,044	$ 13,127,749	$ 261,835		$ 13,285,749	(158,000)
Office Rent	3,054,287	3,224,287	170,000	3,117,009	62,722		3,117,009	-
Office Costs	3,795,572	3,740,288	(55,284)	4,359,340	563,768		4,280,607	78,733
Professional Services	2,509,300	2,414,300	(95,000)	2,468,135	(41,165)		2,468,135	-
Miscellaneous	36,500	37,500	1,000	37,000	500		37,000	-
Depreciation	2,641,943	2,558,606	(83,336)	1,691,457	(950,486)		1,691,457	-
Total Operating Expenses	**$ 24,903,515**	**$ 25,947,939**	**$ 1,044,424**	**$ 24,800,690**	**$ (102,825)**	**-0.4%**	**$ 24,879,956**	**$ (79,267)**
Total Direct Expenses	**$ 65,807,608**	**$ 66,883,471**	**$ 1,075,863**	**$ 66,814,907**	**$ 1,007,299**	**1.5%**	**$ 66,936,699**	**$ (121,792)**
Indirect Expenses	**$ -**	**$ 0**	**$ 0**	**$ 0**	**$ 0**		**$ -**	**$ 0**
Other Non-Operating Expenses	**$ 110,000**	**$ 100,668**	**$ (9,332)**	**$ 106,725**	**$ (3,275)**	**-3.0%**	**$ 122,100**	**$ (15,375)**
Total Expenses (B)	**$ 65,917,608**	**$ 66,984,139**	**$ 1,066,531**	**$ 66,921,632**	**$ 1,004,024**	**1.5%**	**$ 67,058,799**	**$ (137,167)**
Change in Assets	**$ 1,584,548**	**$ 1,095,336**	**$ (489,211)**	**$ 3,230,028**	**$ 1,645,481**		**$ 2,809,163**	**420,865**
Fixed Assets								
Depreciation	$ (2,641,943)	$ (2,558,606)	83,336	$ (1,691,457)	$ 950,486		$ (1,691,457)	$ -
Computer & Software CapEx	2,447,000	2,362,402	(84,598)	2,572,000	125,000	**10.5%**	1,672,000	900,000
Furniture & Fixtures CapEx	-	-	-	-	-		-	-
Equipment CapEx	1,464,000	1,545,797	81,797	1,800,000	336,000		1,800,000	-
Leasehold Improvements	-	-	-	-	-		-	-
Allocation of Fixed Assets	**$ (0)**	$ (0)	$ 0	$ 0	$ 0		**$ -**	**$ 0**
Inc(Dec) in Fixed Assets (C)	**1,269,057**	**1,349,593**	**80,535**	**2,680,543**	**1,411,486**		**1,780,543**	**900,000**
TOTAL BUDGET (=B + C)	**$ 67,186,665**	**$ 68,333,732**	**$ 1,147,067**	**$ 69,602,175**	**$ 2,415,510**	**3.6%**	**$ 68,839,343**	**$ 762,833**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)[1]	**$ 315,490**	**$ (254,257)**	**$ (569,747)**	**$ 549,485**	**$ (716,491)**		**$ 1,028,620**	**$ (479,135)**
FTEs	**192.5**	**188.6**	**(3.9)**	**189.88**	**(2.6)**	**-1.3%**	**193.11**	**(3.23)**

[1]The budgeted change in working capital reflects both a reduction in excess working capital and operating reserves and the assumptions related to capital financing. Refer to Table B-1 on page 81 for a complete analysis of the Working Capital and Operating Reserve balance.

Statement of Activities and Fixed Assets Expenditures 2016 and 2017 Budgets

STATUTORY

	2016 Budget	2016 CRISP Budget	2016 Budget w/out CRISP	2017 Budget	2017 CRISP Budget	2017 Budget w/out CRISP	Variance 2017 Budget v 2016 Budget Over(Under)	% Inc 2017 over 2016
Funding								
ERO Funding								
NERC Assessments	$ 57,081,445	$ 1,108,641	$ 55,972,805	$ 59,856,314	$ 1,275,681	$ 58,580,633	$ 2,607,828	**4.7%**
Penalty Sanctions	1,439,000	33,572	$ 1,405,428	1,100,000	26,243	1,073,757	(331,671)	
Total NERC Funding	**$ 58,520,445**	**$ 1,142,213**	**$ 57,378,232**	**$ 60,956,314**	**$ 1,301,923**	**$ 59,654,390**	**$ 2,276,158**	
Third-Party Funding (CRISP)	6,830,738	6,830,738	$ -	6,990,447	6,990,447	$ -	-	
Testing Fees	1,867,972	-	$ 1,867,972	1,921,900	-	$ 1,921,900	53,928	
Services & Software	50,000	-	$ 50,000	50,000	-	$ 50,000	-	
Workshops	230,000	-	$ 230,000	230,000	-	$ 230,000	-	
Interest	3,000	68	$ 2,932	3,000	70	$ 2,930	(2)	
Miscellaneous	-	-	$ -	-	-	$ -	-	
Total Funding (A)	**$ 67,502,155**	**$ 7,973,019**	**$ 59,529,136**	**$ 70,151,660**	**$ 8,292,440**	**$ 61,859,220**	**$ 2,330,084**	**3.9%**
Expenses								
Personnel Expenses								
Salaries	$ 28,842,336	$ 592,724	$ 28,249,612	$ 30,073,438	$ 603,432	$ 29,470,007	$ 1,220,394	
Payroll Taxes	1,871,367	32,899	$ 1,838,469	1,847,130	32,329	$ 1,814,801	(23,668)	
Benefits	3,579,280	50,247	$ 3,529,034	3,643,806	68,375	$ 3,575,431	46,398	
Retirement Costs	2,990,823	65,802	$ 2,925,021	3,076,956	64,236	$ 3,012,721	87,700	
Total Personnel Expenses	**$ 37,283,807**	**$ 741,671**	**$ 36,542,135**	**$ 38,641,331**	**$ 768,371**	**$ 37,872,960**	**$ 1,330,825**	**3.6%**
Meeting Expenses								
Meetings	$ 1,096,500	$ 30,000	$ 1,066,500	$ 1,071,500	$ 30,000	$ 1,041,500	$ (25,000)	
Travel	2,203,786	37,455	$ 2,166,331	2,203,786	37,455	$ 2,166,331	(0)	
Conference Calls	320,000	2,000	$ 318,000	97,600	2,237	$ 95,363	(222,637)	
Total Meeting Expenses	**$ 3,620,286**	**$ 69,455**	**$ 3,550,831**	**$ 3,372,886**	**$ 69,692**	**$ 3,303,194**	**$ (247,637)**	**-7.0%**
Operating Expenses								
Consultants & Contracts	$ 12,865,914	$ 5,888,594	$ 6,977,320	$ 13,127,749	$ 5,888,594	$ 7,239,155	$ 261,835	
Office Rent	3,054,287	-	$ 3,054,287	3,117,009	-	$ 3,117,009	62,722	
Office Costs	3,795,572	304,027	$ 3,491,545	4,359,340	305,683	$ 4,053,657	562,112	
Professional Services	2,509,300	175,000	$ 2,334,300	2,468,135	175,000	$ 2,293,135	(41,165)	
Miscellaneous	36,500	250	$ 36,250	37,000	250	$ 36,750	500	
Depreciation	2,641,943	-	$ 2,641,943	1,691,457	5,297	$ 1,686,159	(955,783)	
Total Operating Expenses	**$ 24,903,515**	**$ 6,367,871**	**$ 18,535,644**	**$ 24,800,690**	**$ 6,374,824**	**$ 18,425,865**	**$ (109,779)**	**-0.6%**
Total Direct Expenses	**$ 65,807,608**	**$ 7,178,997**	**$ 58,628,611**	**$ 66,814,907**	**$ 7,212,888**	**$ 59,602,019**	**$ 973,409**	**1.7%**
Indirect Expenses	**$ -**	**$ 650,361**	**$ (650,361)**	**$ 0**	**$ 687,169**	**$ (687,169)**	**$ (36,809)**	
Other Non-Operating Expenses	**$ 110,000**	**$ -**	**$ 110,000**	**$ 106,725**	**$ -**	**$ 106,725**	**$ (3,275)**	**-3.0%**
Total Expenses (B)	**$ 65,917,608**	**$ 7,829,358**	**$ 58,088,250**	**$ 66,921,632**	**$ 7,900,057**	**$ 59,021,575**	**$ 933,325**	**1.6%**
Change in Assets	**$ 1,584,548**	**$ 143,662**	**$ 1,440,886**	**$ 3,230,028**	**$ 392,383**	**$ 2,837,645**	**$ 1,396,759**	
Fixed Assets								
Depreciation	$ (2,641,943)	$ -	$ (2,641,943)	$ (1,691,457)	$ (5,297)	$ (1,686,159)	$ 955,783	
Computer & Software CapEx	2,447,000	100,000	2,347,000	2,572,000	350,000	2,222,000	(125,000)	
Furniture & Fixtures CapEx	-	-	-	-	-	-	-	
Equipment CapEx	1,464,000	-	1,464,000	1,800,000	-	1,800,000	336,000	
Leasehold Improvements	-	-	-	-	-	-	-	
Allocation of Fixed Assets	**$ (0)**	$ 43,105	$ (43,105)	$ 0	$ 47,681	$ (47,681)	$ (4,575)	
Inc(Dec) in Fixed Assets (C)	**1,269,057**	**143,105**	**1,125,952**	**2,680,543**	**392,383**	**2,288,160**	**1,162,208**	**103.2%**
TOTAL BUDGET (=B + C)	**$ 67,186,665**	**$ 7,972,463**	**$ 59,214,202**	**$ 69,602,175**	**$ 8,292,440**	**$ 61,309,735**	**$ 2,095,533**	**3.5%**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)[1]	**$ 315,490**	**$ 556**	**$ 314,934**	**$ 549,485**	**$ -**	**$ 549,485**	**$ 234,551**	
FTEs	**192.47**	**2.8**	**189.71**	**189.88**	**2.8**	**187.06**	**(2.6)**	**-1.4%**

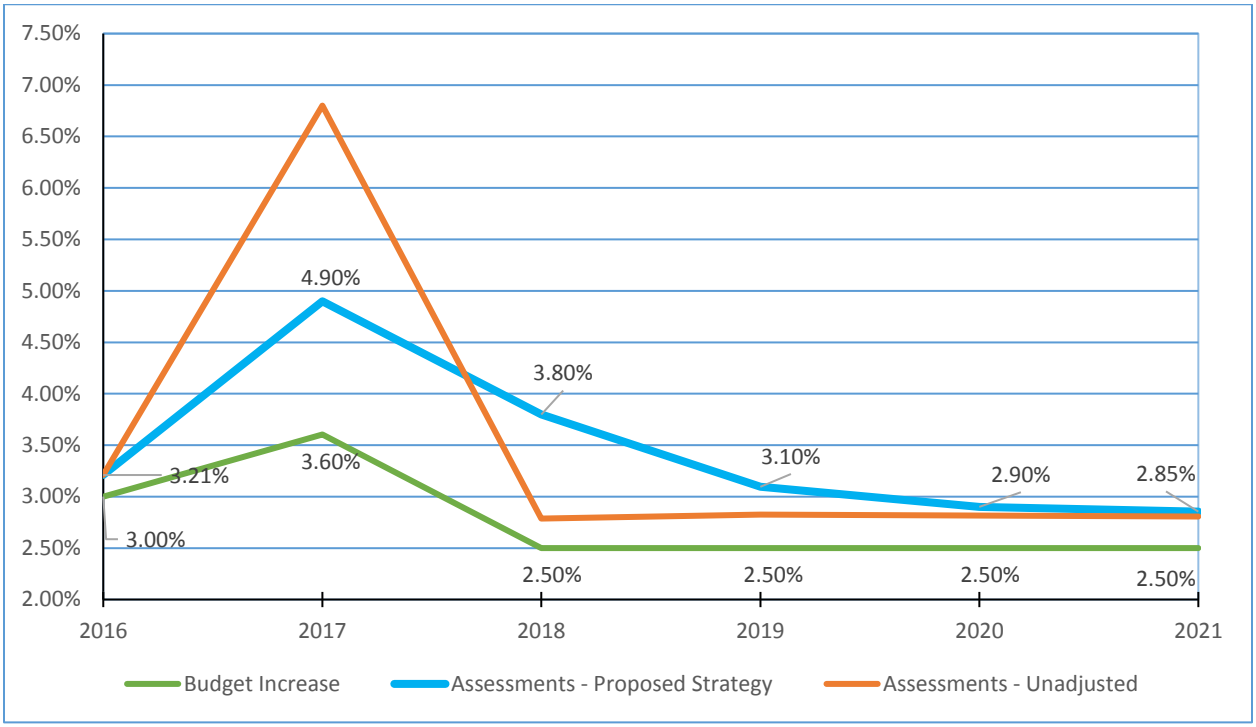
Projections for 2018–2019

Management has developed preliminary operating and fixed asset (capital) projections for 2018 and 2019. The significant assumptions considered in preparing these projections include:

- No increases in total FTEs over the 2017 budget
- Personnel and benefit cost increases are consistent with the 2017 budget assumptions
- Operating costs, including contractor and consulting expenses, are slightly higher due to increases in contract costs for rent, maintenance costs associated with software applications supporting ERO Enterprise Operations, and ongoing implementation of improved budgeting and financial reporting tools.
- Debt service repayment obligations in connection with the company's Capital Financing Program consistent with the projected Enterprise IT Applications capital forecast
- No increase in CRISP-related expenditures, except for personnel and benefit cost increases as noted above

Assessments are projected to increase by gradually declining percentages during the next three years as NERC implements a stabilization strategy. The goal of this strategy is to align budgeted costs and assessment increases more closely so that the unanticipated receipt of penalties will not cause large variances in future assessment projections. Currently, NERC projects assessments to increase 4.5% in 2017, 3.8% in 2018, and 3.1% in 2019 with declining releases each year from the Assessment Stabilization Reserve to meet these targets. A summary of these projections and reserve releases are shown in the table below. A budget increase of 2.5% was used for modeling purposes and is subject to change. The assessment strategy is also depicted in the graph below, showing the assumed budget increases, unadjusted assessment increases, and implementation of the assessment strategy.

	Budget	Assessment	----- Assessment Stabilization Reserve -----		
Year	Increase	Increase	Additions	Uses	Balance
2016	3.00%	3.21%	$ 3,710,000	$ (1,439,000)	$ 2,271,000
2017	3.60%	4.90%	1,000,000	(1,100,000)	2,171,000
2018	2.50%	3.80%	-	(410,000)	1,761,000
2019	2.50%	3.10%	-	(270,000)	1,491,000



The model does not assume any penalties beyond those we currently expect in 2016 and 2017 and includes $500k in penalty funds which NERC is scheduled receive in 2017 under the terms of an existing settlement agreement will be contributed to the Assessment Stabilization Reserve. While both the unexpected receipt of additional penalties and the current balance could yield a sizable amount of funds, future unexpected budget increases, ERO system development projects, or other one-time costs may be appropriate uses of these funds in order to stabilize assessments in the future.[16]

[16] In determining the amount of the Assessment Stabilization Reserve that is released each year, the company's Working Capital and Operating Reserve Policy requires that the NERC Finance and Audit Committee and Board review a three-year forecast of assessments, as well as the availability of funding for this reserve from surplus funds and penalty funds. The actual contributions and releases from the Assessment Stabilization Reserve in any year must be approved as part of NERC's annual business plan and budget process, with opportunity for review and input by stakeholders.

Statement of Activities and Fixed Assets Expenditures
2017 Budget & Projected 2018 and 2019 Budgets

	2017 Budget	2018 Projection	$ Change 18 v 17	% Change 18 v 17	2019 Projection	$ Change 19 v 18	% Change 19 v 18
Funding							
ERO Funding							
NERC Assessments	$ 59,856,314	$ 62,143,946	$ 2,287,633	3.8%	$ 64,088,553	$ 1,944,607	3.1%
Penalty Sanctions	1,100,000	410,000	(690,000)	-62.7%	-	(410,000)	-100.0%
Total NERC Funding	**$ 60,956,314**	**$ 62,553,946**	**$ 1,597,633**	**2.6%**	**$ 64,088,553**	**$ 1,534,607**	**2.5%**
Third-Party Funding (CRISP)	6,990,447	6,990,447	-	0.00%	6,990,447	-	0.0%
Testing Fees	1,921,900	1,921,900	-	0.00%	1,921,900	-	0.0%
Services & Software	50,000	50,000	-	0.00%	50,000	-	0.0%
Workshops	230,000	230,000	-	0.00%	230,000	-	0.0%
Interest	3,000	3,000	-	0.00%	3,000	-	0.0%
Miscellaneous	-		-			-	
Total Funding (A)	**$ 70,151,660**	**$ 71,749,293**	**$ 1,597,633**	**2.3%**	**$ 73,283,900**	**$ 1,534,607**	**2.1%**
Expenses							
Personnel Expenses							
Salaries	$ 30,073,438	$ 31,035,788	$ 962,350	3.2%	$ 31,966,862	$ 931,074	3.0%
Payroll Taxes	1,847,130	1,869,296	22,166	1.2%	1,893,597	24,301	1.3%
Benefits	3,643,806	3,887,941	244,135	6.7%	4,152,321	264,380	6.8%
Retirement Costs	3,076,956	3,141,573	64,616	2.1%	3,264,094	122,521	3.9%
Total Personnel Expenses	**$ 38,641,331**	**$ 39,934,598**	**$ 1,293,267**	**3.3%**	**$ 41,276,874**	**$ 1,342,276**	**3.4%**
Meeting Expenses							
Meetings	$ 1,071,500	$ 1,081,500	$ 10,000	0.9%	$ 1,071,500	(10,000)	-0.9%
Travel	2,203,786	2,203,786	-	0.0%	2,203,786	-	0.0%
Conference Calls	97,600	97,600	-	0.0%	97,600	-	0.0%
Total Meeting Expenses	**$ 3,372,886**	**$ 3,382,886**	**$ 10,000**	**0.3%**	**$ 3,372,886**	**$ (10,000)**	**-0.3%**
Operating Expenses							
Consultants & Contracts	$ 13,127,749	13,595,592	467,844	3.6%	14,367,077	771,485	5.7%
Office Rent	3,117,009	3,099,048	(17,961)	-0.6%	3,104,557	5,509	0.2%
Office Costs	4,359,340	4,359,340	-	0.0%	4,359,340	-	0.0%
Professional Services	2,468,135	2,652,075	183,940	7.5%	2,661,992	9,917	0.4%
Miscellaneous	37,000	37,000	-	0.0%	37,000	-	0.0%
Depreciation	1,691,457	1,194,345	(497,112)	-29.4%	932,549	(261,796)	-21.9%
Total Operating Expenses	**$ 24,800,690**	**$ 24,937,400**	**$ 136,711**	**0.6%**	**$ 25,462,516**	**$ 525,116**	**2.1%**
Total Direct Expenses	**$ 66,814,907**	**$ 68,254,885**	**$ 1,439,978**	**2.2%**	**$ 70,112,277**	**$ 1,857,392**	**2.7%**
Indirect Expenses	**$ -**	**$ -**			**$ -**	**$ -**	
Other Non-Operating Expenses	**$ 106,725**	**$ 114,000**	**$ 7,275**	**6.8%**	**116,000**	**2,000**	**1.8%**
Total Expenses (B)	**$ 66,921,632**	**$ 68,368,885**	**$ 1,447,253**	**2.2%**	**$ 70,228,277**	**1,859,392**	**2.7%**
Change in Assets	**$ 3,230,028**	**$ 3,380,408**	**$ 150,380**	**4.7%**	**$ 3,055,623**	**$ (324,785)**	**-9.6%**
Fixed Assets					-		
Depreciation	$ (1,691,457)	$ (1,194,345)	$ 497,112	-29.4%	$ (932,549)	$ 261,796	-21.9%
Computer & Software CapEx	2,572,000	2,562,000	(10,000)	-0.4%	2,112,000	(450,000)	-17.6%
Furniture & Fixtures CapEx	-	-	-		-	-	
Equipment CapEx	1,800,000	1,585,000	(215,000)	-11.9%	1,705,000	120,000	7.6%
Leasehold Improvements	-	-	-		-	-	
Allocation of Fixed Assets							
Inc(Dec) in Fixed Assets (C)	**$ 2,680,543**	**$ 2,952,655**	**$ 272,112**	**10.2%**	**$ 2,884,451**	**$ (68,204)**	**-2.3%**
TOTAL BUDGET (=B + C)	**$ 69,602,175**	**$ 71,321,540**	**$ 1,719,364**	**2.5%**	**$ 73,112,727**	**$ 1,791,188**	**2.5%**
FTEs	**189.88**	**189.88**	**-**		**189.88**	**-**	

Section A — 2015 Business Plan and Budget Program Area and Department Detail

Reliability Standards

Reliability Standards Program (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget - Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	17.98	17.16	(0.82)	17.66	(0.51)
Direct Expenses	$ 3,888,768	$ 3,861,666	$ (27,102)	$ 3,817,110	$ 44,556
Indirect Expenses	4,234,020	4,180,279	(53,741)	4,244,336	(64,056)
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	70,328	58,337	(11,991)	78,490	(20,153)
TOTAL BUDGET	$ 8,193,116	$ 8,100,282	$ (92,835)	$ 8,139,935	$ (39,653)

Background and Scope

The reliability standards program carries out the ERO's statutory responsibility to develop, adopt, obtain approval of, and modify (as and when appropriate) mandatory reliability standards (both continent-wide standards and regional reliability standards) for the reliable planning, operation, and critical infrastructure protection of the North American BES. The major activities undertaken by the Standards department include:

- **Delivering high-quality, continent-wide reliability standards**: NERC standard developers and other standards staff provide project management and leadership to develop solutions necessary to address reliability risks identified through the Reliability Risk Management Process (RRMP). These may include the development of, or modifications to, NERC reliability standards through standard development outreach activities, facilitation of drafting team activities, drafting support, assisting drafting teams in maintaining adherence to the development process as outlined in the *Standard Processes Manual*, and ensuring that the quality of documents produced is appropriate for approval by industry and the Board.
- **Facilitating continent-wide industry engagement**: NERC manages the work of over 200 industry contributors who serve on the Standards Committee, subgroups, and other project teams for the development of NERC reliability standards through the standards development program.
- **Conducting balloting, disseminating information, and supporting regulatory filings**: Through NERC's commenting and ANSI-accredited balloting process, industry consensus is built by engaging thousands of industry volunteers within hundreds of registered entities throughout North America who review, comment on, and approve the standards created by the standard drafting teams. The department also supports the filing of standards with regulatory authorities and provides support with regulatory proceedings.

The reliability standards program provides a mechanism for the eight Regional Entities to process regional standards when unique regional reliability gaps are detected, or incorporate Regional variances into continent-wide standards. The NERC Standards department staff supports regional standards development processes by providing technical advice, final quality review of regional standards, presentation to the Board, and preparation of regional standards materials for submission for standard adoption to the applicable regulatory authorities in the United States and Canada.

Stakeholder Engagement and Cost Effectiveness Project

As part of the standard development process, industry technical experts scope, draft, and review the new or revised NERC reliability standards for approval by the industry ballot body, adoption by the Board, and filing with regulatory authorities in the United States and Canada. Additionally, Federal, State and Provincial regulatory authorities, the NERC Board of Trustees, Regional Entities, and many industry stakeholders have expressed interest in the identification of costs incurred from implementing NERC reliability standards compared to risks they address. The desire is to ensure that these elements are considered during the standards development and revision process. A pilot was conducted in 2016 to develop an approach to determine the level of cost versus the reliability benefit to mitigate an identified risk. Work will continue in 2017 on refining the approach.

Key Efforts Underway

NERC will ensure that the Reliability Standards Development Plan is effectively executed and that reliability standards are focused on and mitigate significant risks to BES reliability. Department resources will be focused on supporting the strategic plan, including but not limited to support of the RRMP and resolving FERC directives. The Standards department will:

1. **Focus on the selection of projects undertaken.** Resources will be expended on issues determined to be a reliability risk through the RRMP (also see Reliability Assessment and System Analysis, and Performance Analysis section for additional detail). The department will apply broader project management skills to implement a variety of solutions to a reliability concern. An effective solution to an identified reliability risk may be a Reliability Standard, or it may be a guideline, information request, training, NERC Alert, technical conference, research, or a combination of these or other tools.
2. **Address FERC directives and respond to FERC orders** through standards development projects, as necessary. Each project will determine whether: (1) the directive will be complied with as issued, (2) there is an equally effective and efficient way to address the concern that fostered the directive, or (3) if there is technical justification (including that the directive has been overcome by events, processes, or advances in technology) that the directive is no longer needed.
3. **Perform Enhanced Periodic Reviews.** In 2016, as the reliability standards reach steady state, industry, NERC, and FERC will determine whether there is a need to make further improvements to the standards through enhanced periodic reviews, that include: (1) a measured review of the content of standards, considering whether the requirements could more effectively mitigate risks to the BPS; (2) whether the standards are results based and drafted with high quality; (3) whether the standards are concise or if the number of requirements could be reduced; and (4) whether compliance expectations are clear.
4. **Facilitate smooth transition to new standards**. This includes working with the Compliance Monitoring and Enforcement, Registration, and Reliability Assessment and System Analysis, and Performance Analysis programs to develop guidelines, webinars, and other activities to support auditor and industry training for the new standards.

The 2017–2019 RSDP will be developed in 2016 in conjunction with the Standards Committee, RISC, and RRMP. It will outline the work plan for the continued evaluation of NERC reliability standards, the Standards department's support of Reliability Risk Management, and resolution of FERC directives. Additionally, associated metrics will be developed and deployed to measure the overall quality of the reliability standard as a basis for measuring needed improvements.

2017 Goals and Deliverables

The transformation of the reliability standards to steady state is nearing completion.[17] Specifically, the majority of FERC directives will be addressed, as well as the remaining recommendations for retiring requirements made by the Paragraph 81 project and the independent experts. The body of standards will be improved while considering quality and content criteria as well as results-based standards principles. The NERC Standards staff will continue to address any new directives issued by FERC as well any reliability risks identified through RRMP or by the RISC for which a Reliability Standard is part of the solution.

Resource Requirements

Personnel

As in prior years, industry engagement is vital to the successful development of standards. The continued transformation of NERC standards to steady state will require additional industry engagement throughout 2016. In 2017, industry subject matter expert engagement requirements will be ongoing as enhanced periodic reviews are performed.

The NERC standards department continues to focus resources on the production of quality standards, rather than solely on the monitoring and execution of the standards process. Workload in the standards area during 2017 is anticipated to remain stable, with no additional personnel resources planned for 2017. The departmental travel expenses are expected to be the same as the 2016 levels, given the anticipated amount of outreach for the number of standards reviews expected to be in process, coupled with cost savings resulting from holding more meetings at NERC's Atlanta and Washington, DC, offices. The FTE reduction set forth in the table at the end of this section is the result of the allocation of standards staff towards more critical activities like cyber security and analytical capabilities

Contractors and Consultants

No contractor and consulting support is budgeted in 2017, which is consistent with the 2016 budget.

[17] As defined in the 2015-2017 RSDP, "steady state" means a stable set of clear, concise, high-quality and technically sound reliability standards that are results based, including retirement of requirements that do little to promote reliability.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
RELIABILITY STANDARDS

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 7,869,295	$ 7,869,295	$ (0)	$ 7,835,213	$ (34,082)	$ 7,871,776	$ (36,563)
Penalty Sanctions	218,376	218,376		159,642	(58,734)	162,725	(3,082)
Total NERC Funding	**$ 8,087,671**	**$ 8,087,671**	**$ (0)**	**$ 7,994,855**	**$ (92,816)**	**$ 8,034,500**	**$ (39,645)**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	105,000	105,000	-	105,000	-	105,000	-
Interest	445	5,374	4,929	427	(18)	435	(8)
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 8,193,116**	**$ 8,198,045**	**$ 4,929**	**$ 8,100,282**	**$ (92,834)**	**$ 8,139,935**	**$ (39,653)**
Expenses							
Personnel Expenses							
Salaries	$ 2,260,735	$ 2,349,773	$ 89,039	$ 2,340,405	$ 79,671	$ 2,300,735	39,670
Payroll Taxes	163,064	168,710	5,646	151,658	(11,406)	161,947	(10,289)
Benefits	327,239	289,808	(37,432)	307,085	(20,154)	291,462	15,623
Retirement Costs	250,560	265,961	15,401	259,407	8,847	259,856	(448)
Total Personnel Expenses	**$ 3,001,598**	**$ 3,074,252**	**$ 72,654**	**$ 3,058,556**	**$ 56,958**	**$ 3,014,000**	**44,556**
Meeting Expenses							
Meetings	$ 207,000	$ 207,000	$ -	$ 207,000	$ -	$ 207,000	-
Travel	271,988	230,000	(41,988)	271,988	-	271,988	-
Conference Calls	133,000	100,000	(33,000)	40,565	(92,435)	40,565	-
Total Meeting Expenses	**$ 611,988**	**$ 537,000**	**$ (74,988)**	**$ 519,553**	**$ (92,435)**	**$ 519,553**	**-**
Operating Expenses							
Consultants & Contracts	$ -	$ -	$ -	$ -	$ -	$ -	-
Office Rent	-	-	-	-	-	-	-
Office Costs	64,622	42,784	(21,838)	51,336	(13,286)	51,336	-
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	210,060	231,843	21,783	231,721	21,661	231,721	-
Total Operating Expenses	**$ 275,182**	**$ 275,127**	**$ (55)**	**$ 283,556**	**$ 8,375**	**$ 283,556**	**$ -**
Total Direct Expenses	**$ 3,888,768**	**$ 3,886,379**	**$ (2,389)**	**$ 3,861,666**	**$ (27,102)**	**$ 3,817,110**	**$ 44,556**
Indirect Expenses	**$ 4,234,020**	**$ 4,458,581**	**$ 224,561**	**$ 4,180,279**	**$ (53,741)**	**$ 4,244,336**	**$ (64,056)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 8,122,788**	**$ 8,344,959**	**$ 222,171**	**$ 8,041,945**	**$ (80,843)**	**$ 8,061,445**	**$ (19,500)**
Change in Assets	**$ 70,328**	**$ (146,914)**	**$ (217,242)**	**$ 58,337**	**$ (11,991)**	**$ 78,490**	**(20,153)**
Fixed Assets							
Depreciation	$ (210,060)	$ (231,843)	$ (21,783)	$ (231,721)	$ (21,661)	$ (231,721)	$ -
Computer & Software CapEx	-	-	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	**$ 280,388**	231,639	(48,749)	290,058	9,670	310,211	(20,153)
Inc(Dec) in Fixed Assets (C)	**70,328**	**(204)**	**(70,532)**	**58,337**	**(11,991)**	**78,490**	**(20,153)**
TOTAL BUDGET (=B + C)	**$ 8,193,116**	**$ 8,344,755**	**$ 151,639**	**$ 8,100,282**	**$ (92,834)**	**$ 8,139,935**	**$ (39,653)**
FTEs	**17.98**	**18.27**	**0.29**	**17.16**	**(0.82)**	**17.66**	**-0.51**

Compliance Monitoring and Enforcement and Organization Registration and Certification

The Compliance Monitoring, Enforcement, and Organization Registration and Certification Program Area's purpose is to monitor, enforce, and ensure registered entity compliance with the ERO's mandatory reliability standards. This program area is addressed by three operational groups: Compliance Assurance (addressing compliance monitoring), Reliability Assurance (addressing Assurance, Organization Registration and Certification), and Compliance Enforcement.

Compliance Assurance

Compliance Assurance addresses the Regional Entities' implementation of the compliance monitoring section of the Compliance Monitoring and Enforcement Program (CMEP). The group works in tandem with Compliance Enforcement, Standards, and Reliability Risk Management.

Compliance Assurance

Compliance Assurance (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	19.36	15.51	(3.85)	15.07	0.44
Direct Expenses	$ 4,559,233	$ 3,816,924	$ (742,308)	$ 3,615,394	$ 201,530
Indirect Expenses	4,559,714	3,779,431	(780,283)	3,621,833	157,598
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	301,956	262,244	(39,712)	264,713	(2,469)
TOTAL BUDGET	$ 9,420,903	$ 7,858,599	$ (1,562,304)	$ 7,501,940	$ 356,659

Background and Scope

NERC's Compliance Assurance group works collaboratively with the eight Regional Entities to ensure effective implementation of risk-based compliance monitoring under the CMEP across the entire ERO Enterprise. This program ensures that Regional Entities monitor registered entities for compliance according to their own specific facts and circumstances, including the entity's inherent risks, evaluation of controls in place to mitigate the inherent risks, as well as any aggravating factors. The CMEP provides for Regional Entities to develop customized compliance oversight plans (COPs) for each registered entity that identifies: 1) the standards or requirements to be monitored; 2) the monitoring processes (tools) for use by the Regional Entities, including compliance audits, self-certification, spot checking, investigations, self-reporting, periodic data submittals, and complaints; and 3) the frequency of monitoring. NERC and the Regional Entities ensure that inherent risk assessments (IRAs) for registered entities begin with a consistent framework and that Regional Entities' implementation of the CMEP coalesce around best practices, data management procedures that address data reporting requirements, integrity, retention, security, and confidentiality.

The Compliance Assurance group's responsibilities include but are not limited to the following major activities and functions:

- Oversight of the quality implementation of the risk-based compliance monitoring program;
- Development of the annual Implementation Plan (IP);
- Oversight of the use of necessary compliance-related processes, procedures, IT platforms, tools, and templates;

- Development and delivery of education and training for ERO Enterprise staff;
- Critical Infrastructure Protection (CIP) Version 5 activities related to education programs that support industry compliance and the integration of risk assessment and internal controls;
- CIP-014-1 training and outreach activities related to effective implementation of the Physical Security Reliability Standard;
- Coordination with the NERC Standards department for standard development to assist in the smooth transition for standards from development to enforceability;
- Support for Regional Entity and industry committees, working groups, and task forces, such as the NERC Compliance and Certification Committee; and
- Industry training for every Reliability Standard approved by FERC.

Stakeholder Engagement and Benefit

NERC continues to promote the Regional Entities' development of customized COPs for registered entities. As the risk-based compliance monitoring approach was implemented in 2015 and 2016, Regional Entities worked closely with stakeholders to develop IRAs and appropriately scope compliance monitoring activities. As this process matures in 2017, Regional Entities will continue to develop customized uses of compliance monitoring tools and frequency of monitoring for each registered entity, based on its IRA. Additionally, NERC continues to promote registered entities' development of effective compliance programs and internal controls, which may provide a benefit in the development of their COPs.

Compliance Assurance continues to work closely with the standard development program to provide compliance information, statistics, and perspectives to drafting teams fostering the development of standards that provide an increased reliability benefit and clarify compliance risks. This collaboration with industry and Standards department staff will occur early in the standard development process by providing draft compliance monitoring guidance, including information on how compliance with draft standards will be determined, as well as input to the drafting teams on the auditability and enforceability of the draft standards. This will ensure that ERO Enterprise tools used in the auditing process, such as the reliability standards auditing worksheet (RSAW), do not expand or modify standards requirements.

NERC also continues to provide industry-focused outreach events and webinars on the ERO Enterprise's approaches to risk-based CMEP activities. The ERO Enterprise staff will continue its webinar series providing guidance on standards and requirements associated with the 2017 risk elements identified for consideration for compliance monitoring.

Key Efforts Underway

Regional Entity Oversight for Risk-Based Compliance Monitoring

Consistent with the goals and objectives set forth in the strategic plan, NERC will continue to implement risk-based compliance monitoring and enforcement as part of its stated objectives of ensuring BES reliability, improving the efficiency and effectiveness of NERC and Regional Entity compliance and enforcement operations, focusing on identified risks and reducing unnecessary burdens on registered entities.

CIP Compliance and Transition

NERC and the Regional Entities continue to manage the smooth implementation of compliance activities for Version 5 and subsequent enhancements to the CIP Standards by providing training, webinars, and other forms of outreach. The ERO Enterprise will continue to provide educational programs to support

industry compliance and the integration of risk assessment and internal controls. In addition, NERC and the Regional Entities will continue supporting the successful implementation and monitoring of the physical security reliability standard.

2017 Goals and Deliverables

The Compliance Assurance group has several goals and deliverables that support the 2016-2019 *ERO Enterprise Strategic Plan.* Resources will be focused on building upon the framework and improvements implemented as a result of the risk-based compliance monitoring activities in 2016. Specific 2017 objectives for this group are:

- Continue to mature the risk-based compliance monitoring program, fully developing customized COPs for registered entities.
- Work closely with NERC's Enforcement and IT departments, as well as staff in the Regional Entities, on improvements to the existing compliance, reporting, analysis tracking system (C-RATS), and other compliance tools to support risk-based activities.
- Support the continued successful implementation of the CIP Version 5 reliability standards and subsequent enhancements that become effective in 2017 and beyond.
- Continue to monitor and support effective implementation and monitoring of the Physical Security Reliability Standard.
- Initiate a training program to support implementation of the common audit procedures for each Reliability Standard, integrating principles from the ERO Auditor Capabilities and Competencies Guide.
- Continue to integrate the standards and compliance functions for clear stakeholder implementation. Support this effort through common set of RSAWs, measures, or successors, for all standards. Initiate a compliance phase-in learning periods for new standards.

These 2017 activities are necessary to further implement risk-based compliance monitoring, including the CIP standards, and integrate the standards and compliance functions. A number of activities that support the implementation of the strategic risk-based reforms are intended to reduce regulatory burden by focusing monitoring according to each registered entity's potential impact on the BPS.

Resource Requirements

Personnel

The 2017 FTE reduction set forth in the table at the end of this section reflects the reallocation of 2016 budgeted FTEs to support key initiatives related to successful implementation and oversight of the risk-based CMEP.

Contractors and Consultants

Funds budgeted for outside consultants to assist in successful implementation of risk-based compliance monitoring have been reduced to $50k. While at a significantly reduced level from the 2016 budget, some resources are necessary to support the transformation of NERC's Compliance Monitoring and Enforcement Program to a risk-based design. In addition, the Information Technology budget includes funding for the maintenance of existing software tools supporting compliance assessment, registration, certification, and enforcement activities, as well as the investigation and development of a business case for future tools supporting ERO Enterprise ERO Enterprise compliance assessment, registration, and certification and enforcement activities.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
COMPLIANCE ASSURANCE

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 9,185,250	$ 9,185,250	$ (0)	$ 7,713,879	$ (1,471,371)	$ 7,362,710	$ 351,169
Penalty Sanctions	$ 235,174	$ 235,174		144,334	(90,840)	138,858	5,476
Total NERC Funding	**$ 9,420,424**	**$ 9,420,424**	**$ (0)**	**$ 7,858,213**	**$ (1,562,212)**	**$ 7,501,569**	**$ 356,644**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	-	-	-	-	-	-	-
Interest	479	4,710	4,231	386	(93)	371	15
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 9,420,903**	**$ 9,425,134**	**$ 4,231**	**$ 7,858,599**	**$ (1,562,305)**	**$ 7,501,940**	**$ 356,659**
Expenses							
Personnel Expenses							
Salaries	$ 3,063,004	$ 2,367,713	$ (695,290)	$ 2,509,618	$ (553,386)	$ 2,342,419	167,199
Payroll Taxes	205,979	159,939	(46,040)	163,335	(42,644)	158,287	5,048
Benefits	351,727	308,546	(43,180)	333,557	(18,170)	315,645	17,912
Retirement Costs	336,902	267,268	(69,634)	276,273	(60,629)	264,902	11,371
Total Personnel Expenses	**$ 3,957,612**	**$ 3,103,467**	**$ (854,145)**	**$ 3,282,783**	**$ (674,828)**	**$ 3,081,253**	**201,530**
Meeting Expenses							
Meetings	$ 60,000	$ 120,000	$ 60,000	$ 60,000	$ -	$ 60,000	-
Travel	276,343	322,000	45,657	276,343	-	276,343	-
Conference Calls	20,000	20,000	-	6,100	(13,900)	6,100	-
Total Meeting Expenses	**$ 356,343**	**$ 462,000**	**$ 105,657**	**$ 342,443**	**$ (13,900)**	**$ 342,443**	**-**
Operating Expenses							
Consultants & Contracts	$ 200,000	$ 115,000	$ (85,000)	$ 50,000	$ (150,000)	$ 50,000	-
Office Rent	-	-	-	-	-	-	-
Office Costs	44,779	38,880	(5,899)	141,198	96,419	141,198	-
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	-	-	-	-	-	-	-
Total Operating Expenses	**$ 245,279**	**$ 154,380**	**$ (90,899)**	**$ 191,698**	**$ (53,581)**	**$ 191,698**	**$ -**
Total Direct Expenses	**$ 4,559,233**	**$ 3,719,847**	**$ (839,386)**	**$ 3,816,924**	**$ (742,309)**	**$ 3,615,394**	**$ 201,530**
Indirect Expenses	**$ 4,559,714**	**$ 3,687,419**	**$ (872,294)**	**$ 3,779,431**	**$ (780,283)**	**$ 3,621,833**	**$ 157,598**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 9,118,947**	**$ 7,407,267**	**$ (1,711,681)**	**$ 7,596,355**	**$ (1,522,592)**	**$ 7,237,227**	**$ 359,128**
Change in Assets	**$ 301,956**	**$ 2,017,868**	**$ 1,715,912**	**$ 262,244**	**$ (39,712)**	**$ 264,713**	**(2,469)**
Fixed Assets							
Depreciation	-	-	-	-	-	-	-
Computer & Software CapEx	-	-	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 301,956	$ 191,574	(110,382)	262,244	(39,712)	$ 264,713	(2,469)
Inc(Dec) in Fixed Assets (C)	**$ 301,956**	**$ 191,574**	**$ (110,382)**	**$ 262,244**	**$ (39,712)**	**$ 264,713**	**$ (2,469)**
TOTAL BUDGET (=B + C)	**$ 9,420,903**	**$ 7,598,841**	**$ (1,822,062)**	**$ 7,858,599**	**$ (1,562,305)**	**$ 7,501,940**	**$ 356,659**
FTEs	**19.36**	**15.11**	**(4.25)**	**15.51**	**(3.85)**	**15.07**	**0.44**

Compliance Analysis, Certification and Registration

Compliance Analysis, Certification and Registration (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	10.14	7.52	(2.62)	9.42	(1.90)
Direct Expenses	$ 2,086,784	$ 1,686,689	$ (400,093)	$ 1,913,981	$ (227,291)
Indirect Expenses	2,387,951	1,832,451	(555,499)	2,263,646	(431,194)
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	158,136	127,149	(30,988)	165,446	(38,297)
TOTAL BUDGET	$ 4,632,871	$ 3,646,289	$ (986,581)	$ 4,343,072	$ (696,783)

Background and Scope

The Reliability Assurance (Assurance, Certification and Registration) group is responsible for a range of requirements and activities embodied in Section 500 (Organization Registration and Certification) and Appendices 5A and 5B of the NERC Rules of Procedure. The group provides technical resource support to standards development, compliance monitoring, and enforcement and ensures that (1) all entities impacting the BES are registered commensurate with risk; (2) all RCs, TOPs, and BAs are certified; (3) conducts industry reliability assurance activities; and (4) compliance gaps identified in reportable events are assessed and addressed if appropriate. Specific activities of the group include:

- **Registration** – Identifies and registers BES users, owners, and operators who are responsible for compliance with reliability standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and complying with all applicable reliability standards. Maintains the current registration for the entire ERO for entities as they take on and drop functional responsibilities.
- **Certification** – Evaluates and certifies the competency of reliability entities; i.e., those that perform certain key reliability functions, specifically the RC, BA, and TOP functions. Entities performing these three functions must be evaluated for having the necessary personnel, knowledge, facilities, programs, and other qualifications to carry out these important responsibilities, including demonstrating the ability to meet the requirements and sub-requirements of all of the reliability standards applicable to the reliability function(s). This also includes confirming through the certification review process that a reliability entity continues to have the qualifications mentioned above following planned material changes to that entity's operation.
- **Reliability Assurance** – Conducts reliability assurance activities, including:
    - **Reliability Assurance** – Conduct activities to reasonably assure the ERO that certain actions have been taken as reported in response to NERC Alerts or guidance to industry. An example of this is the Right-of-Way Clearances, which is one of the 2015 ERO Enterprise high-priority risk projects.
    - **Oversight** – NERC provides oversight of Regional Entity implementation of regional registration, compliance, certification, investigation, complaint programs, and processes.
    - **Investigations** – Staff conducts non-public, confidential investigations to identify Possible Violations of NERC reliability standards in response to complaints, BES disturbances, or other similar triggers. Staff participates on all Regional Entity-led investigations and observe as requested on FERC-led reliability investigations and inquiries.

- **Compliance evaluations** – Staff works closely with regional staff to confirm that qualified events and disturbances are evaluated against the relevant approved reliability standards and ensure formal compliance monitoring occurs if indicated. These analyses are also shared with FERC staff.
- **Complaints** – NERC addresses formal complaints that allege the violation of reliability standards through a confidential process.

Key Efforts Underway

In 2014 and 2015, the Reliability Assurance, Certification and Registration group developed the risk-based Registration (RBR) design and registration criteria. FERC approved the design in 2015 in two orders, March 15 and October 15, which included the deactivation of Interchange Authorities (IAs), Load Serving Entities (LSEs) and Distribution Providers below 75 MW (DPs), as well as the creation of a NERC-led panel (Panel). In 2016, the ERO Enterprise implemented the Panel to review entities for deregistration or applicability to a reduced number of standards. The Panel will continue to review registration for individual entities and evaluate trends to determine emerging classes of similarly situated entities in 2017. In 2016, a review and identification of potential improvements in both the Registration and Certification programs is being undertaken. Improvements identified, will be considered for implementation in 2017.

2017 Goals and Deliverables

The Reliability Assurance group has several goals and deliverables that support the 2016-2019 *ERO Enterprise Strategic Plan.* Resources will be focused on building upon the improvements identified in 2016. Specific 2017 objectives for this group are:

- Continue to mature the NERC-led panel.
- Implement registration program improvements identified in the 2016 project, and conduct any additional actions identified by the project. Conduct training as necessary.
- Implement certification program improvements identified in the 2016 project and conduct training as necessary.

Resource Requirements

Personnel

No additional personnel are budgeted for 2017. The FTE count in the table at the end of this section reflects the 2016 merger of the registration and reliability assurance groups.

Contractor Expenses

No contractor expenses are budgeted in 2017.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
COMPLIANCE ANALYSIS, CERTIFICATION and REGISTRATION

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)
Funding					
ERO Funding					
NERC Assessments	$ 4,509,458	$ 4,509,458	$ 0	$ 4,256,053	$ (253,404)
Penalty Sanctions	$ 123,162	$ 123,162		86,786	(36,376)
Total NERC Funding	**$ 4,632,620**	**$ 4,632,620**	**$ 0**	**$ 4,342,840**	**$ (289,780)**
Third-Party Funding	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	251	251	0	232	(19)
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 4,632,871**	**$ 4,632,871**	**$ 0**	**$ 4,343,072**	**$ (289,799)**
Expenses					
Personnel Expenses					
Salaries	$ 1,410,333	$ 1,276,351	$ (133,982)	$ 1,284,717	$ (125,615)
Payroll Taxes	97,779	89,383	(8,396)	89,953	(7,826)
Benefits	184,238	200,291	16,053	208,842	24,604
Retirement Costs	157,451	144,473	(12,977)	145,981	(11,470)
Total Personnel Expenses	**$ 1,849,801**	**$ 1,710,498**	**$ (139,302)**	**$ 1,729,494**	**$ (120,307)**
Meeting Expenses					
Meetings	$ 4,000	$ 3,000	$ (1,000)	$ 4,000	$ -
Travel	155,146	134,000	(21,146)	155,146	-
Conference Calls	2,000	2,000	-	610	(1,390)
Total Meeting Expenses	**$ 161,146**	**$ 139,000**	**$ (22,146)**	**$ 159,756**	**$ (1,390)**
Operating Expenses					
Consultants & Contracts	$ 50,000	$ 50,000	$ -	$ -	$ (50,000)
Office Rent	-	-	-	-	-
Office Costs	25,338	17,365	(7,972)	24,231	(1,106)
Professional Services	-	-	-	-	-
Miscellaneous	500	500	-	500	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 75,838**	**$ 67,865**	**$ (7,972)**	**$ 24,731**	**$ (51,106)**
Total Direct Expenses	**$ 2,086,784**	**$ 1,917,364**	**$ (169,420)**	**$ 1,913,981**	**$ (172,803)**
Indirect Expenses	**$ 2,387,951**	**$ 2,274,301**	**$ (113,650)**	**$ 2,263,646**	**$ (124,305)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 4,474,734**	**$ 4,191,664**	**$ (283,070)**	**$ 4,177,626**	**$ (297,108)**
Change in Assets	**$ 158,136**	**$ 441,207**	**$ 283,070**	**$ 165,446**	**$ 7,309**
Fixed Assets					
Depreciation	-	-	-	-	-
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	$ 158,136	$ 118,030	(40,107)	165,446	7,309
Inc(Dec) in Fixed Assets (C)	**$ 158,136**	**$ 118,030**	**$ (40,107)**	**$ 165,446**	**$ 7,309**
TOTAL BUDGET (=B + C)	**$ 4,632,871**	**$ 4,309,694**	**$ (323,177)**	**$ 4,343,072**	**$ (289,799)**
FTEs	**10.14**	**9.55**	**(0.59)**	**9.42**	**(0.72)**

Compliance Enforcement

Compliance Enforcement (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	12.22	13.16	0.94	12.25	0.91
Direct Expenses	$ 2,225,938	$ 2,371,347	$ 145,410	$ 2,376,067	$ (4,720)
Indirect Expenses	2,876,962	3,206,790	329,827	2,942,739	264,050
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	190,398	222,510	32,112	215,079	7,431
TOTAL BUDGET	$ 5,293,298	$ 5,800,647	$ 507,350	$ 5,533,886	$ 266,761

Background and Scope

The Compliance Enforcement department is responsible for overseeing enforcement processes, the application of penalties or sanctions, and activities to mitigate and prevent recurrence of noncompliance with reliability standards. The Compliance Enforcement department works collaboratively with the eight Regional Entities to ensure consistent and effective implementation of the risk-based Compliance Monitoring and Enforcement Program. Importantly, the department also focuses on ensuring that the ERO Enterprise dedicates resources to the matters that pose the greatest risk to reliability.

The NERC Compliance Enforcement department performs its responsibilities by:

- Monitoring Regional Entities' enforcement processes and providing oversight over their outcomes to ensure due process, to identify best practices and process efficiency opportunities, and to promote consistency among Regional Entities' business practices;
- Collecting and analyzing compliance enforcement data and trends to assist with the identification of emerging risks and to help inform the development of enforcement policies and processes;
- Filing notices of penalty and other submittals associated with noncompliance discovered through Regional Entity compliance monitoring and enforcement activities;
- Processing and filing notices of penalty and other submittals associated with violations discovered through NERC-led investigations and audits;
- Collaborating with other NERC departments, including Compliance Assurance, Standards, Event Analysis, and Regional Entity Coordination; and
- Delivering training of the ERO Enterprise staff and registered entities, as well as supporting other outreach efforts.

The ERO Enterprise's enforcement jurisdiction is drawn from the Energy Policy Act of 2005 (the Act), which added section 215 to the Federal Power Act (FPA). Section 215 made compliance with electric reliability standards mandatory and authorized the creation of an ERO and Regional Entities to establish and enforce reliability standards. Under section 215(e)(1) of the FPA, NERC or a Regional Entity may impose a penalty on a user, owner, or operator of the BPS for a violation of a Reliability Standard approved by FERC. As the ERO, NERC has set forth Sanction Guidelines outlined in its Rules of Procedure that govern the ERO Enterprise's penalties and non-monetary sanctions for Reliability Standard violations. This document provides information on the ERO Enterprise's enforcement philosophy, i.e., the ERO Enterprise's approach for assessing and resolving noncompliance while continuing to work to bring entities into compliance with applicable reliability standards.

ERO Enterprise Core Values and Guiding Principles

The ERO Enterprise's 2016-2019 Strategic Plan[18] promotes the ERO Enterprise's core values and guiding principles, which are based on accountability and independence, responsiveness, fairness and inclusiveness, adaption and innovation, excellence, efficiency, and integrity. These core values and guiding principles support the four pillars of the ERO Enterprise's efforts, namely, reliability, assurance, learning, and a risk-based approach.

Strategic Goals Related to Enforcement

Strategic goal 2 provides that the ERO Enterprise shall:

> [b]e a strong enforcement authority that is independent, without conflict of interest, objective and fair, and promote a culture of reliability excellence through risk-informed compliance monitoring and enforcement. The ERO Enterprise retains and refines its ability to use standards enforcement when warranted and imposes penalties and sanctions commensurate with risk. The ERO Enterprise retains and refines its ability to use reliability standards enforcement when warranted and imposes penalties and sanctions commensurate with risk.

The risk-based enforcement approach allows for the appropriate allocation of resources to the issues that pose a higher level of risk to the reliability of the BPS.

Guiding Enforcement Principles

The following principles serve as guidelines for the conduct and behavior of all involved in the ERO Enterprise enforcement program to ensure alignment with strategic goal 2 and the ERO Enterprise's core values.

Compliance Enforcement Authorities are independent, without conflict of interest, objective, and fair.

The ERO Enterprise strives to be a strong enforcement authority that is independent, without conflict of interest, objective, and fair. NERC and each of the Regional Entities has a code of conduct addressing the professional and ethical standards applicable to its personnel. Foremost among these standards is the requirement that no person work on a matter where that work may affect the person's financial interest. The ERO Enterprise also expects its personnel to conduct themselves professionally and respectfully when engaging with registered entities or other stakeholders. Personnel who do not meet these standards are subject to discipline, up to and including termination.

Enforcement program promotes culture of reliability excellence through a risk-based approach.

The ERO Enterprise's risk-based enforcement philosophy generally advocates reserving enforcement actions under section 5.0 of the Compliance Monitoring and Enforcement Program for those issues that pose a higher risk to the reliability of the BPS. The risk of a noncompliance is determined based on specific facts and circumstances, including any controls in place at the time of the noncompliance. The ERO Enterprise works with registered entities to ensure timely remediation of potential risks to the reliability of the BPS and prevent recurrence of noncompliance. The enforcement process allows parties to address risks collaboratively and promote increased compliance and reliability through improvement of programs and controls at the registered entities.

The ERO Enterprise applies a presumption of non-enforcement treatment of minimal risk noncompliance to entities with demonstrated internal controls who are permitted to self-log such minimal risk issues. Regarding other issues posing a minimal risk, NERC and the Regional Entities may exercise appropriate

[18] The ERO Enterprise's 2016-2019 Strategic Plan

judgment whether to initiate a formal enforcement action or resolve the issue outside of the formal enforcement processes. The availability of streamlined treatment of minimal risk noncompliance outside of the formal enforcement process encourages self-inspection by registered entities. When self-identified minimal risk noncompliance is more than likely not going to be subject to a financial penalty, registered entities are encouraged to establish more robust internal controls for the detection and correction of noncompliance. This approach allows the ERO Enterprise to oversee the activities of registered entities in a more efficient manner and to focus resources where they result in the greatest benefit to reliability. In this context, efficiency does not necessarily mean less time or effort. Rather, it is using the requisite time, knowledge, and skills required for each circumstance. In addition, this approach allows the ERO Enterprise to continue to provide clear signals to registered entities about identified areas of concern and risk prioritization, while maintaining existing visibility into potential noncompliance and emerging areas of risk. Outcomes for noncompliance are based on the risk of a specific noncompliance and may range from streamlined, non-enforcement processes, to significant monetary penalties.

Enforcement actions are used and penalties are imposed when warranted, commensurate with risk.
An element of a risk-based approach to enforcement is accountability of registered entities for their noncompliance. No matter the risk of the noncompliance, the registered entity still bears the responsibility of mitigating that noncompliance. Based on the risk, facts, and circumstances associated with that noncompliance, the Regional Entity decides on an appropriate disposition track, inside or outside of an enforcement action, as described above, and whether a penalty is appropriate for the noncompliance.

Penalties are generally warranted for serious risk violations (e.g., uncontrolled loss of load, CIP program failures) and for when repeated noncompliance constitutes an aggravating factor. In addition to the use of significant penalties to deter undesired behavior, the ERO Enterprise also incents desired behaviors.[19] Specifically, Regional Entities may offset penalties to encourage valued behavior. Factors that may mitigate penalty amounts include registered entity cooperation, accountability (including admission of violations), culture of compliance, and self-identification of noncompliance.

Regional Entities may also grant credit in enforcement determinations for certain actions undertaken by registered entities for improvements in addition to mitigating factors. For example, Regional Entities may consider significant investments in reliability made by registered entities, beyond those otherwise planned and required, as an offset for proposed penalties in enforcement determinations. Regional Entities do not award credits or offsets for actions or investments undertaken by a registered entity that are required to mitigate noncompliance.

NERC engages in regular oversight of Regional Entity enforcement activities to confirm that the Regional Entities have followed the CMEP. This oversight evaluates the consistency of disposition methods, including assessment of a penalty or sanction, with previous resolutions of similar noncompliance involving similar circumstances. The NERC Board of Trustees Compliance Committee (the Compliance Committee) considers the recommendations of NERC staff regarding approval of Full Notices of Penalty and monitors the handling of noncompliance through the streamlined disposition methods of Spreadsheet NOPs, FFTs, and Compliance Exceptions.

[19] The Sanction Guidelines, Appendix 4B to the NERC Rules of Procedure, in alignment with Section 215, establish a general rule that penalties and sanctions imposed for the violation of a Reliability Standard shall bear a reasonable relation to the seriousness of the violation while also reflecting consideration of the other factors specified in the Sanction Guidelines. The Sanction Guidelines are available on NERC's website.

Actions are timely and transparent.
The ERO Enterprise maintains an elevated level of transparency regarding enforcement matters. NERC's Rules of Procedure (including the CMEP and Sanction Guidelines) and program documents are available to the public.[20] NERC also posts information on enforcement actions on a monthly basis.[21] Moreover, information on the efficiency of the enforcement program is available to the public on a quarterly basis.[22]

Noncompliance information is used as an input to other processes.
When developing risk elements, NERC annually identifies and prioritizes risks to the reliability of the BPS, taking into account factors such as compliance findings, event analysis experiences, and data analysis. In addition, Regional Entities consider factors such as noncompliance information when conducting an IRA of a registered entity. The ERO Enterprise also uses noncompliance information as part of a feedback loop to the standards development process. This allows enhanced reliability standards through appropriate information flows from compliance monitoring and enforcement to the standards drafting process and other NERC programs. NERC regularly provides analysis and lessons learned from noncompliance information to the public.[23]

Stakeholder Engagement and Benefit

Over the past few years, NERC and the Regional Entities have made substantial progress in reducing the number of instances of noncompliance remaining to be evaluated and processed. The ERO Enterprise has held registered entities accountable for instances of noncompliance that posed a risk to the reliability of the BPS while ensuring that enforcement actions are timely and transparent. NERC promotes a culture of reliability excellence by examining registered entities' internal compliance programs and considering them as mitigating factors in penalty determinations.

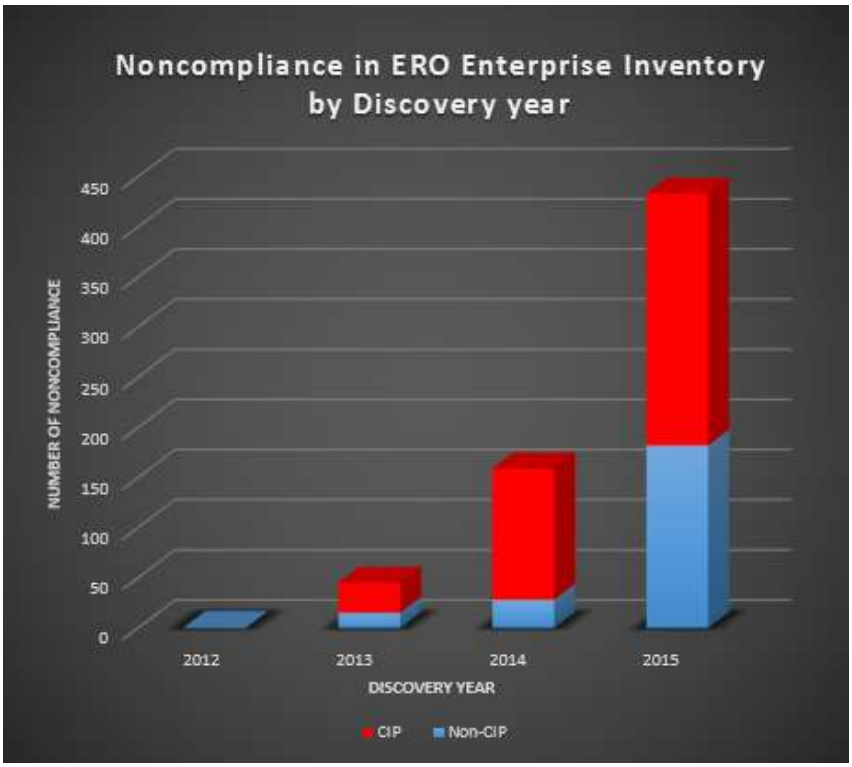
Processing Efficiencies

In an effort to improve the efficiency of enforcement processing throughout the ERO Enterprise, NERC developed a series of key enforcement processing metrics, which are tracked and analyzed throughout the year. In addition, since 2012, NERC has established goals to reduce the number of older violations remaining to be processed. Working with NERC, the Regional Entities invested significant time and resources in processing the older violations. As a result, the ERO Enterprise as a whole reduced the number of older violations substantially.

As of the end of 2015, there were three hundred twenty (320) violations older than 24 months. Sixty-four (64) of these violations stemmed from 9 non-federal registered entities and two hundred fifty-six (256) violations derived from 13 federal registered entities. The vast majority of the violations have either been fully mitigated or have mitigation plans in progress.

The targets and thresholds for processing efficiency-related metrics remain the same in 2016. This is because the ERO Enterprise is stable with regard to enforcement processing. This has only been possible due to the hard work of the Regional Entities and NERC Enforcement in eliminating backlog and incorporating new enforcement processes and procedures into practice.

[20] The NERC Rules of Procedure
[21] Posted compliance exceptions, Spreadsheet Notices of Penalty, and Full Notices of Penalty
[22] Quarterly enforcement program
[23] Quarterly compliance reports



Continued Outreach Efforts in 2016 and Beyond

In 2016, NERC and the Regional Entities will continue to conduct outreach activities that focus on self-logging, compliance exceptions, risk elements, CIP Version 5, Inherent Risk Assessments, and internal controls. NERC plans to use existing industry events, such as the Standards and Compliance workshops and industry webinars, to provide information on compliance monitoring and enforcement activities.

In addition, NERC and the Regional Entities will conduct industry outreach on reliability standards approved by FERC in 2016. These events will focus on the approved new standards or modifications to existing standards along with implementation timelines. Although most events will take place via webinar, some events will be delivered as workshops.

Risk-Based CMEP Implementation

On February 19, 2015, FERC approved the implementation of the risk-based CMEP. The goal of the risk-based CMEP is to shift the compliance and enforcement approach from one in which all instances of noncompliance are evaluated as Possible Violations to an approach that strengthens management practices and reserves the enforcement process for instances of noncompliance that have been found to pose a greater risk to reliability. The programs discussed below, in conjunction with compliance outreach encouraging the development of strong management practices, will advance NERC's progress toward this goal.

Compliance Exceptions

A compliance exception is an alternative disposition method and is not a dismissal, Find, Fix, Track (FFT), or Notice of Penalty. It is essentially the exercise of enforcement judgment with respect to a noncompliance regardless of its method of discovery (self-report, self-certification, compliance audit finding, etc.). The process of identifying and recording a compliance exception builds on the FFT program. The ERO Enterprise uses judgment in the process by taking into account the facts and circumstances of the noncompliance, the risk posed by the noncompliance to the reliability of the BPS, and the deterrent

effect of an enforcement action or penalty, among other things. Compliance exception treatment is available for issues that pose a minimal risk to the BPS that would be mitigated within 12 months of the date the compliance exception is posted.

In 2013 and 2014, the use of compliance exceptions (as the alternative disposition for noncompliance posing a minimal risk to the reliability of the BPS) was limited to allow the testing of the new process. In 2015, this disposition track became available throughout the ERO Enterprise. Use of compliance exceptions as a disposition track has increased steadily. Minimal risk issues continue to be the majority of the caseload. Regional Entities have continued to use the compliance exception disposition method and increasingly relied upon it for minimal-risk issues. The increase in compliance exception use has corresponded with a decline in the use of the FFT disposition track.



Self-Logging

NERC and Regional Entity enforcement staff also have worked closely with stakeholders to identify potential improvements to self-reporting and other enforcement processes. A number of improvements were designed and implemented in 2013 and 2014. The self-logging program allows registered entities that have demonstrated effective management practices to keep track of minimal-risk noncompliance (and related mitigation) on a log that is periodically reviewed by the Regional Entity.

In November 2015, FERC approved the ERO Enterprise Self-Logging Program document, which includes the method to evaluate eligibility.[24] The program is available to any registered entity that would like to be evaluated by its Regional Entity in accordance with the program requirements. Self-logging became available to all registered entities that met the program qualifications at the start of 2015, and 42 registered entities have been approved by Regional Entities to self-log as of December 31, 2015. NERC is conducting a review of the self-logging program, in coordination with FERC staff, during 2016.

NERC Oversight of Risk-Based CMEP Implementation

For 2016, ensuring the successful implementation of NERC's risk-based CMEP remains the priority of Compliance Enforcement's oversight plan. As part of that oversight and in addition to offering regular feedback to the Regional Entities, NERC will continue to identify areas for improvement or promoting

[24] *North American Electric Reliability Corporation*, 153 FERC ¶ 61,130 (2015). The self-logging program document is available on NERC's website.

consistency through training, guidance, or adjustment the following year. NERC also produces an ERO Enterprise CMEP annual report, which includes an assessment of the risk-based CMEP implementation. NERC expects to publish that report during Q1 2017.

NERC performs oversight of the Regional Entities' enforcement programs primarily through the review of the processes, supporting evidence, and other information provided by the Regional Entities over the course of focused engagements of program areas that are scheduled throughout the year. NERC communicates the recommendations and findings to the Regional Entities to help the ERO Enterprise develop responsive strategies and solutions to potential issues and ensure uniform and consistent implementation of the CMEP. Such recommendations and findings also help identify priority areas for training of ERO Enterprise staff during the year.

Other Key Enforcement Efforts Underway

Regional Entity Training

NERC Enforcement will provide training to Regional Entity staff on the most important elements of risk-based enforcement, including risk assessment of noncompliance and the determination of appropriate penalties and sanctions for noncompliance. NERC is developing this training based on observations from its oversight activities of Regional Entity settlement agreements, as well as the process reviews described above.

2017 Goals and Deliverables

Specific 2017 objectives for the Compliance Enforcement department include:

- Refining and improving the risk-based CMEP processes;
- Implementing in a transparent manner an ERO Enterprise enforcement philosophy that is risk focused and drives desired behaviors by registered entities;
- Expanding the feedback loop of information from Enforcement to Standards and other program areas; and
- Working closely with NERC's Compliance Assurance and Information Technology departments, as well as staff in the Regional Entities, regarding the evaluation of improvements in the existing compliance, reporting, analysis tracking system, and other compliance tools to support risk-based activities.

Resource Requirements

Personnel

No changes to current Enforcement staffing levels are proposed in 2017.

Contractor Expenses

The Information Technology budget includes funding for the maintenance, evaluation, and development of enterprise tools supporting technical feasibility exceptions, registration, and enforcement activities.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
COMPLIANCE ENFORCEMENT

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 5,144,612	$ 5,144,612	$ 0	$ 5,677,854	$ 533,242	$ 5,420,762	$ 257,092
Penalty Sanctions	148,384	$ 148,384		122,465	(25,919)	112,822	9,643
Total NERC Funding	**$ 5,292,996**	**$ 5,292,996**	**$ 0**	**$ 5,800,319**	**$ 507,323**	**$ 5,533,584**	**$ 266,735**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	-	-	-	-	-	-	-
Interest	302	3,682	3,380	327	25	302	26
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 5,293,298**	**$ 5,296,678**	**$ 3,380**	**$ 5,800,647**	**$ 507,349**	**$ 5,533,886**	**$ 266,761**
Expenses							
Personnel Expenses							
Salaries	$ 1,629,233	$ 1,755,799	$ 126,566	$ 1,790,859	$ 161,627	$ 1,791,830	(971)
Payroll Taxes	109,485	113,380	3,895	117,205	7,720	117,447	(241)
Benefits	222,877	176,404	(46,473)	184,106	(38,771)	185,432	(1,326)
Retirement Costs	181,419	196,458	15,039	198,694	17,275	200,877	(2,182)
Total Personnel Expenses	**$ 2,143,014**	**$ 2,242,042**	**$ 99,028**	**$ 2,290,865**	**$ 147,851**	**$ 2,295,585**	**(4,720)**
Meeting Expenses							
Meetings	$ 2,500	$ 2,500	$ -	$ 2,500	$ -	$ 2,500	-
Travel	56,736	55,000	(1,736)	56,736	-	56,736	-
Conference Calls	1,200	2,000	800	366	(834)	366	-
Total Meeting Expenses	**$ 60,436**	**$ 59,500**	**$ (936)**	**$ 59,602**	**$ (834)**	**$ 59,602**	**$ -**
Operating Expenses							
Consultants & Contracts	$ -	$ -	$ -	$ -	$ -	$ -	-
Office Rent	-	-	-	-	-	-	-
Office Costs	21,866	14,983	(6,883)	20,379	(1,486)	20,379	-
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	1,000	500	500	-	500	-
Depreciation	122	122	-	-	(122)	-	-
Total Operating Expenses	**$ 22,488**	**$ 16,105**	**$ (6,383)**	**$ 20,879**	**$ (1,608)**	**$ 20,879**	**$ -**
Total Direct Expenses	**$ 2,225,938**	**$ 2,317,647**	**$ 91,708**	**$ 2,371,347**	**$ 145,409**	**$ 2,376,067**	**$ (4,720)**
Indirect Expenses	**$ 2,876,962**	**$ 2,989,470**	**$ 112,507**	**$ 3,206,790**	**$ 329,827**	**$ 2,942,739**	**$ 264,050**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 5,102,901**	**$ 5,307,116**	**$ 204,216**	**$ 5,578,137**	**$ 475,236**	**$ 5,318,807**	**$ 259,330**
Change in Assets	**$ 190,398**	**$ (10,438)**	**$ (200,836)**	**$ 222,510**	**$ 32,112**	**$ 215,079**	**7,431**
Fixed Assets							
Depreciation	(122)	(122)	-	-	122	-	-
Computer & Software CapEx	-	107,000	107,000	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 190,520	$ 155,313	(35,207)	222,510	31,990	$ 215,079	7,431
Inc(Dec) in Fixed Assets (C)	**$ 190,398**	**$ 262,191**	**$ 71,793**	**$ 222,510**	**$ 32,112**	**$ 215,079**	**$ 7,431**
TOTAL BUDGET (=B + C)	**$ 5,293,298**	**$ 5,569,308**	**$ 276,009**	**$ 5,800,647**	**$ 507,349**	**$ 5,533,886**	**$ 266,761**
FTEs	**12.22**	**12.25**	**0.03**	**13.16**	**0.94**	**12.25**	**0.91**

Reliability Assessment and System Analysis

Reliability Assessments and System Analysis (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	11.75	14.10	2.35	14.13	(0.03)
Direct Expenses	$ 3,778,595	$ 3,986,965	$ 208,370	$ 4,031,697	$ (44,731)
Indirect Expenses	2,768,236	3,435,846	667,610	3,395,468	40,378
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	(202,709)	112,782	315,491	122,547	(9,765)
TOTAL BUDGET	$ 6,344,123	$ 7,535,594	$ 1,191,470	$ 7,549,713	$ (14,119)

Background and Scope

The Reliability Assessment and System Analysis (RASA) department carries out the ERO's statutory responsibility to conduct assessments of the reliability and adequacy of the BES. These assessments are used to provide insight and guidance about reliability risks. These insights provide a foundation for the development of new reliability standards or modifications to mandatory reliability standards, or other initiatives, such as guidelines, alert(s), webinars, etc., all focused on enhancing overall reliability. The majority of the activities in the RASA department directly address the risk priorities established by the Reliability Issues Steering Committee. In particular, the risks pertaining to changing resources and planning noted in the 2015 RISC report are of particular importance to the assessment and analysis work being performed in RASA.

NERC staff works closely with stakeholders on creating assessment development schedules, including schedules with adequate stakeholder review at every level. All NERC reliability assessments have a sponsoring technical committee, subcommittee, or other subgroup. The Long-Term and Seasonal assessments are conducted by the Reliability Assessment Subcommittee, and ultimately endorsed by the Planning Committee. Special Assessments often require a separate and specialized task force or advisory group to help construct, conduct, and produce special topic assessments such as the CPP assessments, Natural Gas interdependency assessment, and distributed energy report.

The department focuses on developing a technical framework and understanding the emerging reliability risks facing the industry. It also provides guidance and insights to stakeholders across North America. The department relies on its own engineering and analysis expertise, as well as Regional Entity and stakeholder resources. RASA is responsible for:

- Independent reliability assessments on the overall reliability and adequacy of the BES and associated emerging reliability risks that could impact the short-, mid- and the long-term (e.g., 10-year) planning horizons, and other reliability issues requiring an in-depth analysis.
- Support for the development and improvement of long-term sustainable interconnection-based power flow, dynamic, and load models that exhibit the accuracy and fidelity reflecting actual BES reliability performance and dynamic conditions.
- Interconnection-wide analysis of steady-state and dynamic conditions, including frequency, Essential Reliability Services, stability, and oscillatory behavior aspects.

- Advancement of industry and the ERO's understanding of power system characteristics and behaviors by gathering larger PMU datasets of data for advanced data analytics and modeling improvements.

- Assurance oversight that the BES electrical elements necessary for its reliable operation are identified, requiring the elements to follow the appropriate NERC Reliability Standards.

- Establishment of reliability leadership and consistent, technically sound guidance and recommendations that position industry and policy makers to enhance reliability through effective outreach and communications.

Stakeholder Engagement and Benefit

RASA works with industry leaders to create a reliability strategy that is relevant, timely, and effective to address the most important reliability risks. This effort includes reviewing and addressing key priority risks identified by NERC's Reliability Issues Steering Committee's (RISC); synthesizing key information identified through analysis and assessment efforts; extracting and prioritizing the associated reliability risks; sharing and integrating risk analysis insights across the ERO Enterprise; and translating that knowledge into actionable guidance and recommendations for NERC management, the Board, and entities, along with state, federal, and provincial policy makers.

In addition, the ERO monitors the ongoing and historic reliability performance of the BES through data gathered to analyze historic trends. The ERO provides reports and recommendations regarding the anticipated conditions that could impact the reliability, security, and stability of the BPS to the industry, Regional Entities, regulatory entities, and other designated entities.

2017 Enhancements

Enhancements in the 2017 BP&B are a reflection of the strategic goals and objectives identified in the Electric Reliability Organization Enterprise Strategic Plan 2016–2019.[25] The following enhancements are attributable to strategic goal #4[26] and the objectives and valued outcomes noted within the goal #4a:

- Improve resource adequacy assessments with increased probabilistic and risk analysis
- Conduct interconnection-wide analysis to support NERC's reliability assessments and improve industry planning
- Increase technical analysis and assessment focus on natural gas, wind, and solar resource and fuel availability
- Develop technical references and guidelines that advance and improve reliability using new technologies
- Develop quality/fidelity assessments of interconnection models

Key RASA Efforts Underway

RASA focuses its efforts in the following key areas:

Reliability Assessment

Reliability assessments serve to evaluate the expected reliability of the BES through extensive deterministic and probabilistic analyses to identify potential reliability risks and potential mitigation approaches. These reviews include both evaluations at the edge of the planning horizon, as well as

[25] http://www.nerc.com/AboutNERC/Documents/ERO%20Enterprise%20Strategic%20Plan%202016%E2%80%932019.pdf

[26] ERO Enterprise identifies, evaluates, studies, and independently assesses emerging risks to reliability.

assessments of the anticipated performance during the short-term (12- to 18-month outlook). These analyses involved planned and anticipated changes to generation resources, transmission infrastructure, and load behavior compared to base-line needs of the system to remain reliable and formulate recommendations and related guidance. This assessment is often by completed by examining special scenarios and unique situations within the BES. These analyses provide a technical platform for important policy discussions on challenges facing the interconnected BES, as well as focused recommendations on mitigation to improve overall reliability or lessen reliability risks.

By identifying and quantifying emerging reliability issues, NERC is able to provide risk-informed recommendations and support a learning environment for industry to address emerging risks and pursue improved reliability performance. These efforts are expected to expand to assess the impacts on reliability from the changing resource mix, reliability behavior of resources, distributed energy resources, and loads. Many resource additions are asynchronous and energy-limited, requiring assessment of a substantial number of scenarios rather than just seasonal peak conditions. Reliability assessments must therefore include a greater focus on probabilistic approaches, assessing the sufficiency of essential reliability services as well as focusing seasonal assessments on short-term horizons to encompass more than peak condition reserve margin analyses.

Key assessments include:

- Long-Term Reliability Assessment (supplemented by the Probabilistic Assessment)
- Summer and Winter Reliability Assessments (condensed report)
- Short-Term and Special Reliability Assessments
    a. Between one and four short-term reliability assessments are expected, driven by the need to assess emerging short-term risks to reliability
    b. Special Assessments are selected based on high-priority/high-risk issues that require an independent assessment from the ERO.

A significant ongoing effort anticipated to involve RASA, Regional Entity staff, and stakeholders focuses on the continued development of effective Essential Reliability Services. These efforts are expected to lead to a broad set of recommendations that will culminate with defined elements, an evaluation of initial metrics and data compilation of actual performance, and refinement about the ongoing assessment of Essential Reliability Services measures.

System Analysis

Understanding the technical behavior of the North American grid is the foundation for identifying crucial aspects of performance that are important for sustaining overall reliability. NERC's understanding of grid behavior is achieved through a comprehensive evaluation of system behavior through constant observation and study, analytic simulations, and forensic analysis of system disturbances. Methodically comparing the simulation results of powerflow and system dynamic performance to actual system behavior improves models critical for industry use to simulate system conditions as well as enables RASA to gain insights to enhance predictive system analysis.

The ERO Enterprise RAPA team also supports the following objectives:

- Continue leading and improving NERC's analytical capabilities to address a broad range of engineering topics,
- Support NERC Reliability Standards development with subject matter expertise,
- Support and lead technical analysis of emerging risks requiring advanced analytics and interconnection-wide assessment,

- Detailed forensic analysis of significant system disturbances

Key focus areas:

- PMU Measurement, use, and analysis improvements
  - Synchrophasor technology
  - Power plant model verification
  - Oscillation analysis
- Frequency Response Analysis, Interconnection Frequency Response Obligation Analysis, and forward-looking reliability assessment
- Interconnection-Wide Model Building Designation and Criteria administration
- Analysis of TPL Footnote 12
- Load and distributed energy resource modeling
- Event analysis – simulation and forensic analysis of major events
- Reliability Standards support
- BES Exception and Self-Determined Notification Processing

Further, RASA will continue to work closely with other organizations, including but not limited to the Electric Power Research Institute (EPRI), the Department of Energy (DOE), the Institute of Electrical and Electronic Engineers (IEEE), the Institute of Nuclear Power Operations (INPO), the North American Transmission Forum (NATF), the North American Generation Forum (NAGF), and the Canadian Electricity Association (CEA). RASA collaborates with these groups on a number of fronts, including geomagnetic disturbance (GMD), vegetation management, and variable generation integration. RASA will continue working with the Interstate Natural Gas Association of America (INGAA) and the Natural Gas Supply Association (NGSA) regarding studies pertaining to the interdependency of gas and electric systems.

2017 Goals and Deliverables

In 2017, RASA will seek to achieve several specific goals and objectives as part of the strategic focus of the ERO Enterprise (Goal 4a):

1. Pioneer implementation of advanced reliability assessment and system analysis methods to address the changing nature of the grid. Issue reliability assessment reports, guidelines, and recommendations to address high priority evolving performance trends and address emerging risks to reliability.
   a. Expand the use of probabilistic assessment tools across the ERO and gain consistency in approach
   b. Special assessments on identified high-priority risks (from RISC prioritization and recommendations)[27]
      - Changing resource mix and maintaining Essential Reliability Services

27 http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Recommendations_to_the_Board.pdf

- Increased penetration of Distributed Energy Resources
- Increasing dependency on generation fueled by natural gas
- Broaden understanding of inter-area and local system oscillations in all interconnections and their potential impact on interconnection reliability.

c. As part of its oversight of the Regional Entities, build and sustain an Enterprise RAPA team (ERO-RAPA) that encompasses the consistent development and implementation of risk-informed approaches and structured methods to identify and address reliability risks.

2. Provide the basis for industry to meet regulatory requirements of the NERC Reliability Standard BAL-003-1, "Frequency Response and Frequency Bias Setting;" exploratory understanding of frequency response; support interconnection-wide studies of frequency response
   a. Frequency Response Annual Analysis and BAL-003 FERC filing
   b. Determination of Interconnection Frequency Response Obligation (IFRO) and BA FRO values
3. Support NERC Reliability Standard development by providing subject matter expertise.
4. Provide support and leadership to (1) the Planning Committee and (2) standing committees' subcommittees, working groups, and task forces serving the standing committees. Support the development of technical reference documents and Reliability Guidelines with support of the PC leadership and established in the annual PC work plan
5. As necessary, support major event investigations, analyses, and reporting of findings, recommendations, and lessons learned to improve reliability.
6. Provide feedback to interconnection-wide model-building groups on improvements to system model quality and fidelity.
7. Assist in the development of approaches to registration and provide input to NERC staff in support of the development CMEP risk elements, as well as support and lead the BES Definition Exception Process.

Resource Requirements

Personnel
Additional personnel were allocated to RASA in 2016 to address increased resource demands associated with ongoing reliability assessment, performance analysis, and system analysis activities.

Contractor Expenses
The total contractor and consultant expenses for the department are projected at $525k, a decrease of $50k from the 2016 budget. Further information is provided on Exhibit C.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
RELIABILITY ASSESSMENTS and SYSTEM ANALYSIS

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 6,135,872	$ 6,135,872	0	$ 7,339,030	$ 1,203,158	$ 7,354,185	$ (15,154)
Penalty Sanctions	142,718	142,718		131,213	(11,505)	130,180	1,033
Total NERC Funding	**$ 6,278,590**	**$ 6,278,590**	**$ 0**	**$ 7,470,243**	**$ 1,191,653**	**$ 7,484,364**	**$ (14,121)**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	50,000	-	(50,000)	50,000	-	50,000	-
Workshops	15,000	15,000	-	15,000	-	15,000	-
Interest	462	3,634	3,172	351	(111)	348	3
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 6,344,052**	**$ 6,297,224**	**$ (46,828)**	**$ 7,535,594**	**$ 1,191,542**	**$ 7,549,713**	**$ (14,119)**
Expenses							
Personnel Expenses							
Salaries	$ 1,826,951	$ 2,080,813	$ 253,862	$ 2,247,826	$ 420,875	$ 2,258,124	(10,298)
Payroll Taxes	122,096	137,089	14,993	142,919	20,823	148,547	(5,628)
Benefits	213,866	240,723	26,857	263,230	49,364	269,401	(6,171)
Retirement Costs	203,274	229,385	26,111	246,609	43,335	251,613	(5,003)
Total Personnel Expenses	**$ 2,366,187**	**$ 2,688,010**	**$ 321,823**	**$ 2,900,585**	**$ 534,398**	**$ 2,927,684**	**(27,100)**
Meeting Expenses							
Meetings	$ 109,000	$ 109,000	$ -	$ 74,000	$ (35,000)	$ 109,000	(35,000)
Travel	208,338	249,000	40,662	208,338	-	208,338	-
Conference Calls	17,280	17,280	-	5,270	(12,010)	5,270	-
Total Meeting Expenses	**$ 334,618**	**$ 375,280**	**$ 40,662**	**$ 287,608**	**$ (47,010)**	**$ 322,608**	**(35,000)**
Operating Expenses							
Consultants & Contracts	$ 575,000	$ 442,425	$ (132,575)	$ 525,000	$ (50,000)	$ 525,000	-
Office Rent	-	-	-	-	-	-	-
Office Costs	116,266	138,523	22,257	147,652	31,386	130,283	17,368
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	386,024	282,034	(103,991)	125,621	(260,403)	125,621	-
Total Operating Expenses	**$ 1,077,790**	**$ 863,482**	**$ (214,308)**	**$ 798,773**	**$ (279,018)**	**$ 781,404**	**$ 17,368**
Total Direct Expenses	**$ 3,778,595**	**$ 3,926,772**	**$ 148,177**	**$ 3,986,965**	**$ 208,370**	**$ 4,031,697**	**$ (44,731)**
Indirect Expenses	**$ 2,768,236**	**$ 3,218,866**	**$ 450,630**	**$ 3,435,846**	**$ 667,610**	**$ 3,395,468**	**$ 40,378**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 6,546,832**	**$ 7,145,638**	**$ 598,806**	**$ 7,422,812**	**$ 875,980**	**$ 7,427,165**	**$ (4,354)**
Change in Assets	**$ (202,780)**	**$ (848,413)**	**$ (645,634)**	**$ 112,782**	**$ 315,562**	**$ 122,547**	**(9,765)**
Fixed Assets							
Depreciation	(386,024)	(282,034)	103,991	(125,621)	260,403	(125,621)	-
Computer & Software CapEx	-	53,580	53,580	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 183,316	$ 167,231	$ (16,084)	238,403	$ 55,088	$ 248,168	(9,765)
Inc(Dec) in Fixed Assets (C)	**$ (202,709)**	**$ (61,222)**	**$ 141,486**	**$ 112,782**	**$ 315,491**	**$ 122,547**	**$ -**
TOTAL BUDGET (=B + C)	**$ 6,344,123**	**$ 7,084,415**	**$ 740,292**	**$ 7,535,594**	**$ 1,191,471**	**$ 7,549,713**	**$ (14,119)**
FTEs	**11.75**	**13.19**	**1.44**	**14.10**	**2.35**	**14.13**	**(0.03)**

Performance Analysis

Performance Analysis (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	6.92	9.40	2.49	9.42	(0.02)
Direct Expenses	$ 1,838,245	$ 2,459,356	$ 621,111	$ 2,460,815	$ (1,459)
Indirect Expenses	1,628,513	2,290,564	662,051	2,263,646	26,918
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	107,841	158,936	51,095	165,446	(6,510)
TOTAL BUDGET	$ 3,574,599	$ 4,908,855	$ 1,334,256	$ 4,889,906	$ 18,949

Background and Scope

The Performance Analysis (PA) group provides insight and guidance about reliability risks and areas of concern based on analysis of historic system performance. This includes identifying potential risks of concern related to system, equipment, entity, and organizational performance that may indicate a need to develop remediation strategies, action plans, or data used to create, revise or retire reliability standards or consider new reliability standards. The department focuses on developing a technical framework and understanding the reliability risks facing the industry.

Stakeholder Engagement and Benefit

The ERO monitors the reliability performance of the BES in North America through data gathered to analyze historic trends. The ERO provides reports and recommendations regarding the anticipated conditions that could impact the reliability, security, and stability of the BPS to the industry, Regional Entities, regulatory entities, and other designated entities.

The ERO works with industry leaders to create a reliability strategy that is relevant, timely, and effective at addressing the most important reliability risks. This effort includes PA's contribution (both in data gathering and in statistical analysis of data, trends, and events) toward the ERO's understanding key information identified through analysis and assessment efforts; extracting and prioritizing the associated reliability risks from that information; sharing and integrating those risk analysis insights across the ERO Enterprise; and translating that knowledge into actionable guidance and recommendations for NERC management, the Board, and entities, and state, federal, and provincial policy makers. This offers stakeholders an open and transparent approach for the development of NERC's reliability strategy, ultimately ensuring the ERO is accountable to industry, regulators, and the public at large.

Key Efforts Underway

Performance Analysis collects transmission outage, generator performance, demand response, and protection and control misoperation data in a common format using the various industry databases. This data is used to develop and report on grid metrics that analyze outage frequency, duration, causes, and many other factors related to transmission and generator performance as well as automatic power system protection and control effectiveness. In addition to collecting simple equipment availability, detailed information about individual outage events is collected that, when analyzed at the regional and NERC levels, provides data that may be used to improve BES reliability.

The key trends, findings, and recommendations from Performance Analysis serve as technical input to the ERO's reliability standards and standards project prioritization, compliance process improvements, event analyses, reliability assessment, and critical infrastructure protection efforts. This analysis of BES performance provides an industry reference for historical BES reliability, but it also offers analytical

insights that lead toward the prioritization of specific actionable risk control steps for industry. These analyses and results are summarized in the annual state of reliability report, which provides guidance and recommendations for enhanced bulk system reliability. By January, 2017, PA will add GADS Wind Data to the data collected under Section 1600, requiring the development of a new software tool to enable this.

Performance Analysis is working with Event Analysis to develop a link between their databases. Specific equipment outages will be linked to disturbance reports filed with NERC, enabling better association of transmission and generation outages. The continued alignment between these efforts is expected to enhance the ability to conduct effective event analyses as well as identify key reliability areas for trend analyses of multiple databases. This is expected to improve the depth of event analyses across the ERO Enterprise and expand the quality of data gathered for sophisticated statistical and probabilistic analyses. This will lead to trends and insights about reliability performance, as well as effective measures and actions to address reliability risks. Further in 2016, PA has begun data mining of completed EA efforts to see if any insight might be gained from these events as the grid evolves that were not front and foremost or particularly relevant to enhanced grid reliability at the time of the original event investigation.

Performance Analysis is currently refining the composition of NERC's annual state of reliability (SOR) report to expand the GADS data trend analysis, and for 2017 begin to reflect post-seasonal reliability review, insights from analysis of transmission, generator, and demand response data systems (TADS, GADS, and DADS), and integration of event analysis and misoperations. Also, in 2016, the department will perform activities necessary to determine whether in 2017 the SOR should move from a calendar year (Q1-Q4) report to a fiscal year (2016,Q4-2017,Q3) report.

Further, Performance Analysis will continue to work closely with other organizations, including but not limited to the Electric Power Research Institute (EPRI), the Department of Energy (DOE), the Institute of Electrical and Electronic Engineers (IEEE), the Institute of Nuclear Power Operations (INPO), the North American Transmission Forum (NATF), the North American Generation Forum (NAGF), and the Canadian Electricity Association (CEA). PA collaborates with these groups on a number of fronts, including TADS, GADS, and DADS.

2017 Goals and Deliverables

In 2017, Performance Analysis has a number of specific goals and deliverables in support of the Strategic Plan, including:

1. Issue the state of reliability report, guidelines, recommendations, alerts as needed (including the verification and validation of data and information through Regional Entities and technical committees as required)
2. Oversee and evaluate reliability trends that identify reliability risks by analyzing data contained in NERC's the Generating, Transmission, and Demand Response Availability Data Systems (GADS, TADS, and DADS), along with reliability metrics and protection & controls system misoperations.
3. Support NERC Reliability Standard development by providing subject matter expertise.
4. Provide support and leadership to the standing committees' subcommittees, working groups, and task forces serving the standing committees (primary focus on the Performance Analysis Subcommittee and its subgroups.
5. Assist in the development of approaches to registration and provide input to NERC staff in support of the development of CMEP risk elements
6. Conduct major event investigations, analyses, and reporting of major findings, recommendations, and lessons learned that will improve reliability.

7. Provide insight on emerging system protection issues, and hand-off any issues gleaned with future implications to RASA.

Resource Requirements

Personnel

During 2016 additional personnel (including open positions) were allocated to Performance Analysis to address increased resource demands associated with ongoing reliability assessment, performance analysis, and system analysis activities.

Contractor Expenses

Performance Analysis contractor and consultant expenses are $528k, an increase of $19k over 2016. Additional details are provided in Exhibit C.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
PERFORMANCE ANALYSIS

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 3,490,625	$ 3,490,625	$ -	$ 4,821,146	$ 1,330,521	$ 4,802,887	$ 18,259
Penalty Sanctions	84,052	84,051		87,475	3,423	86,786	689
Total NERC Funding	**$ 3,574,677**	**$ 3,574,676**	**$ -**	**$ 4,908,621**	**$ 1,333,944**	**$ 4,889,674**	**$ 18,948**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	50,000	50,000	-	-	-	-
Workshops		-	-	-	-	-	-
Interest		2,554	2,554	234	234	232	2
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 3,574,677**	**$ 3,627,230**	**$ 52,554**	**$ 4,908,855**	**$ 1,334,178**	**$ 4,889,906**	**$ 18,949**
Expenses							
Personnel Expenses							
Salaries	$ 886,643	$ 1,280,436	$ 393,793	$ 1,349,579	$ 462,936	$ 1,341,820	7,760
Payroll Taxes	65,373	90,958	25,585	92,093	26,720	95,140	(3,048)
Benefits	126,252	142,204	15,952	143,104	16,852	154,659	(11,556)
Retirement Costs	98,314	144,446	46,132	149,018	50,704	151,902	(2,885)
Total Personnel Expenses	**$ 1,176,582**	**$ 1,658,044**	**$ 481,462**	**$ 1,733,794**	**$ 557,212**	**$ 1,743,522**	**(9,728)**
Meeting Expenses							
Meetings	$ 1,000	$ 6,000	$ 5,000	$ 1,000	$ -	$ 1,000	-
Travel	118,172	98,000	(20,172)	118,172	-	118,172	-
Conference Calls	9,720	7,000	(2,720)	2,965	(6,755)	2,965	-
Total Meeting Expenses	**$ 128,892**	**$ 111,000**	**$ (17,892)**	**$ 122,137**	**$ (6,755)**	**$ 122,137**	**-**
Operating Expenses							
Consultants & Contracts	$ 509,039	$ 621,849	$ 112,810	$ 528,082	$ 19,043	$ 546,082	(18,000)
Office Rent	-	-	-	-	-	-	-
Office Costs	23,732	51,194	27,462	74,843	51,111	48,574	26,269
Professional Services	-	-	-	-	-	-	-
Miscellaneous		-	-	500	500	500	-
Depreciation		-	-	-	-	-	-
Total Operating Expenses	**$ 532,771**	**$ 673,043**	**$ 140,272**	**$ 603,426**	**$ 70,655**	**$ 595,156**	**$ 8,269**
Total Direct Expenses	**$ 1,838,245**	**$ 2,442,087**	**$ 603,842**	**$ 2,459,356**	**$ 621,111**	**$ 2,460,815**	**$ (1,459)**
Indirect Expenses	**$ 1,628,513**	**$ 2,242,712**	**$ 614,200**	**$ 2,290,564**	**$ 662,051**	**$ 2,263,646**	**$ 26,918**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 3,466,758**	**$ 4,684,799**	**$ 1,218,041**	**$ 4,749,920**	**$ 1,283,162**	**$ 4,724,460**	**$ 25,459**
Change in Assets	**$ 107,919**	**$ (1,057,569)**	**$ (1,165,487)**	**$ 158,936**	**$ 51,016**	**$ 165,446**	**(6,510)**
Fixed Assets							
Depreciation		-	-	-	-	-	-
Computer & Software CapEx	-	162,500	162,500	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 107,841	$ 116,517	$ 8,676	158,936	$ 51,095	$ 165,446	(6,510)
Inc(Dec) in Fixed Assets (C)	**$ 107,841**	**$ 279,017**	**$ 171,176**	**$ 158,936**	**$ 51,095**	**$ 165,446**	**$ -**
TOTAL BUDGET (=B + C)	**$ 3,574,599**	**$ 4,963,816**	**$ 1,389,217**	**$ 4,908,855**	**$ 1,334,257**	**$ 4,889,906**	**$ 18,949**
FTEs	**6.92**	**9.19**	**2.28**	**9.40**	**2.49**	**9.42**	**(0.02)**

Reliability Risk Management

NERC's Reliability Risk Management (RRM) group carries out the ERO's statutory responsibility to perform assessments (real time or near real time continual awareness, detailed analysis of significant events, and longer-tern broad performance assessments) of the reliability and adequacy of the BES, including identifying potential issues of concern relating to system, equipment, entity, and human performance that may indicate the need to develop and implement targeted interventions. RRM has three departments: Situation Awareness (also referred to as Bulk Power System Awareness), Event Analysis, and Performance Analysis, as described above beginning on page 53. These departments are responsible for six primary functions: (1) BES awareness; (2) event analysis and determination of root and contributing causes; (3) assessment of human performance challenges that affect BES reliability and identification of improvement opportunities; (4) continent-wide analysis and reporting of BES performance; (5) support of the NERC Operating Committee; and (6) support of the NERC Critical Infrastructure Protection Committee.

RRM's functions and resources are directly focused on proactive awareness of BES conditions and all events over a threshold of certain risk or impact. Through awareness and continuous assessment, RRM identifies potential reliability risks to the BES. RRM analyzes events in detail, addresses the most significant risks to BES reliability, and ensures that industry is well informed of system events, emerging trends, risk analysis, and lessons learned. Through performing these functions, RRM provides data and analysis to inform the other aspects of NERC's statutory functions. The group also provides strategic direction for using risk-based concepts in planning and executing its responsibilities.

Situation Awareness

Situation Awareness (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget - Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	5.53	5.64	0.11	5.65	(0.01)
Direct Expenses	$ 2,310,875	$ 2,570,828	$ 259,953	$ 2,509,043	$ 61,785
Indirect Expenses	1,302,775	1,374,338	71,563	1,358,187	16,151
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	78,547	87,695	9,148	91,601	(3,906)
TOTAL BUDGET	$ 3,692,197	$ 4,032,862	$ 340,664	$ 3,958,831	$ 74,030

Background and Scope

NERC's Situation Awareness department and the eight Regional Entities monitor BES conditions, significant occurrences and emerging risks, and threats across the 14 Reliability Coordinator regions in North America to maintain an understanding of conditions and situations that could impact the bulk electric system's reliable operation. This group also supports the development and publication of Alerts and awareness products and facilitates information sharing among industry, Regions, and the government during crisis situations and major system disturbances. The process for understanding the potential threats or vulnerabilities to the reliability of the BPS starts with understanding occurrences and events in the context in which they occur.

Stakeholder Engagement and Benefit

BES conditions continually change and provide recognizable signatures through automated tools, mandatory reports and voluntary information sharing, and third-party publicly available sources. The significant majority of these signatures represents conditions and occurrences that have little or no

reliability impact, either positive or adverse, on the BES. However, being cognizant of the short-term condition of the BES and the signatures associated with the entire range of reliability performance helps the ERO identify significant occurrences and events more accurately and efficiently. Registered entities continue to robustly share information and collaborate with the ERO in an effort to maintain and improve the overall reliability of the grid.

Key Efforts Underway

Several reliability-related situation awareness and monitoring tools will undergo enhancement, replacement, streamlining, or modification. The following tools are being focused on during 2016: (1) operation and maintenance of Situation Awareness for NERC, FERC, and Regions, Version 2 (SAFNRv2) software application used for monitoring, to include preparation for a new RFP process in late 2016 to enhance the tool from its current state with no changes to the data used; (2) operation and maintenance of the current secure NERC Alerts tool while planning for a streamlined NERC Alert process and platform appropriately integrated with related ongoing NERC, E-ISAC and ERO Enterprise IT initiatives; (3) refresh of the Reliability Coordinator Information System (RCIS) legacy application for operability and maintainability reasons, with no significant changes to functionality; and (4) continuing to set the conditions to bring limited streaming Synchrophasor data into NERC for wide-area situational awareness and event triage applications.

2017 Goals and Deliverables

In 2017, the Situation Awareness department will seek to accomplish the following specific goals and deliverables:

1. Ensure that the ERO is aware of all BES events above a threshold of impact.
2. Enable the sharing of information and data to facilitate wide-area situational awareness.
3. During crisis situations, facilitate the exchange of information among industry, Regions, and the U.S. and Canadian governments.
4. Keep industry informed of emerging reliability threats and risks to the BES, including any expected actions.
5. Conduct the annual NERC Monitoring and Situational Awareness Conference and Human Performance Conference.
6. Administer the NERC Alerts process as specified in ROP §810 to issue Advisory (Level 1) Alerts on significant and emerging reliability- and security-related topics as needed, and facilitate the tracking of actions specified in Recommendation (Level 2) and Essential Action (Level 3) Alerts.

The department uses the following major reliability-related tools to support department activities:

Resource Adequacy (ACE Frequency) Tool

This software application provides continuous monitoring of key resource adequacy performance metrics, including pre-established thresholds and limits defined in standards. It alerts Reliability Coordinators and resource subcommittees to conditions that could result in critical inadequacies, such as major tie errors, inaccurate load forecasts, and inadequate frequency response.

Inadvertent Interchange

This tool facilitates the entering of monthly scheduling data and submittal of monthly inadvertent performance standards reports to NERC. It also assists in the monitoring and resolution of reliability issues originated by inadvertent interchange imbalances.

Frequency Monitoring and Analysis Tool

This tool detects frequency events and captures key frequency response information for each interconnection.

Intelligent Alarms Tool

This tool detects short-term and long-term frequency deviations using data transmitted to NERC by the Balancing Authorities. When coupled with the FNet[28] and Frequency Monitoring and Analysis tools, this tool allows immediate differentiation of the cause of a frequency deviation—a generator trip or a scheduling error.

Genscape

The PowerIQ and PowerRT tools provide more detailed insight into current-day conditions impacting BPS conditions in both normal operations and stressed conditions.

Resource Requirements

Personnel

No additional personnel are projected for the Situation Awareness department in 2017. The slight increase reflected in the following table is due to a lower vacancy rate than in 2016.

Contractor Expenses

The overall funding of approximately $1.3M for contractors and consultants (which includes the cost of the tools set forth above) to support the Situation Awareness department in 2017 represents an increase of $84k over 2016 budget levels. The detailed 2017 contractor and consulting budget for the Situation Awareness department is set forth in Exhibit C with a comparison to 2016 budgeted amounts.

[28] FNet – Operated by the Power Information Technology Laboratory at the University of Tennessee, FNET is a low-cost, quickly deployable global positioning system (GPS)-synchronized wide-area frequency measurement network. High dynamic accuracy Frequency Disturbance Recorders (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.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
SITUATION AWARENESS

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 3,624,868	3,624,868	$ 0	$ 3,980,236	$ 355,369	$ 3,906,620	$ 73,616
Penalty Sanctions	67,193	67,193	0	52,485	(14,708)	52,072	413
Total NERC Funding	**$ 3,692,060**	**$ 3,692,060**	**$ 0**	**$ 4,032,721**	**$ 340,661**	**$ 3,958,692**	**$ 74,029**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	-	1,128	1,128	-	-	-	-
Interest	137	1,816	1,679	140	3	139	1
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 3,692,197**	**$ 3,695,004**	**$ 2,807**	**$ 4,032,862**	**$ 340,664**	**$ 3,958,831**	**$ 74,030**
Expenses							
Personnel Expenses							
Salaries	$ 764,342	$ 787,436	$ 23,094	$ 873,869	$ 109,527	$ 780,907	92,962
Payroll Taxes	58,235	59,443	1,208	58,749	515	59,423	(674)
Benefits	101,765	135,367	33,601	156,328	54,563	142,213	14,115
Retirement Costs	85,275	88,342	3,067	96,159	10,884	90,776	5,382
Total Personnel Expenses	**$ 1,009,617**	**$ 1,070,587**	**$ 60,971**	**$ 1,185,105**	**$ 175,488**	**$ 1,073,320**	**111,785**
Meeting Expenses							
Meetings	$ 6,500	$ 5,000	$ (1,500)	$ 6,500	$ -	$ 6,500	-
Travel	33,005	32,500	(505)	33,005	-	33,005	-
Conference Calls	1,000	1,000	-	305	(695)	305	-
Total Meeting Expenses	**$ 40,505**	**$ 38,500**	**$ (2,005)**	**$ 39,810**	**$ (695)**	**$ 39,810**	**$ -**
Operating Expenses							
Consultants & Contracts	$ 1,211,475	$ 1,268,777	$ 57,302	$ 1,295,850	$ 84,375	$ 1,345,850	(50,000)
Office Rent	-	-	-	-	-	-	-
Office Costs	41,052	39,540	(1,512)	41,897	845	41,897	-
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	7,727	7,727	-	7,667	(60)	7,667	-
Total Operating Expenses	**$ 1,260,754**	**$ 1,316,544**	**$ 55,790**	**$ 1,345,914**	**$ 85,160**	**$ 1,395,914**	**$ (50,000)**
Total Direct Expenses	**$ 2,310,875**	**$ 2,425,631**	**$ 114,756**	**$ 2,570,828**	**$ 259,953**	**$ 2,509,043**	**$ 61,785**
Indirect Expenses	**$ 1,302,775**	**$ 1,391,019**	**$ 88,243**	**$ 1,374,338**	**$ 71,563**	**$ 1,358,187**	**$ 16,151**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 3,613,650**	**$ 3,816,649**	**$ 202,999**	**$ 3,945,167**	**$ 331,516**	**$ 3,867,230**	**$ 77,936**
Change in Assets	**$ 78,547**	**$ (121,645)**	**$ (200,192)**	**$ 87,695**	**$ 9,148**	**$ 91,601**	**(3,906)**
Fixed Assets							
Depreciation	(7,727)	(7,727)	-	(7,667)	60	(7,667)	-
Computer & Software CapEx	-	-	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 86,273	$ 72,268	(14,005)	95,361	9,088	$ 99,267	(3,906)
Inc(Dec) in Fixed Assets (C)	**$ 78,547**	**$ 64,542**	**$ (14,005)**	**$ 87,695**	**$ 9,148**	**$ 91,601**	**$ -**
TOTAL BUDGET (=B + C)	**$ 3,692,197**	**$ 3,881,191**	**$ 188,994**	**$ 4,032,862**	**$ 340,664**	**$ 3,958,831**	**$ 74,030**
FTEs	**5.53**	**5.70**	**0.17**	**5.64**	**0.11**	**5.65**	**(0.01)**

Event Analysis Department

Event Analysis (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	11.06	11.28	0.22	11.30	(0.02)
Direct Expenses	$ 2,650,065	$ 2,592,388	$ (57,676)	$ 2,686,020	$ (93,631)
Indirect Expenses	2,605,551	2,748,677	143,126	2,716,375	32,302
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	100,179	105,141	4,962	112,953	(7,812)
TOTAL BUDGET	$ 5,355,795	$ 5,446,206	$ 90,411	$ 5,515,347	$ (69,141)

Background and Scope

The Event Analysis department performs assessments of the reliability and adequacy of the BES. This includes identifying potential issues of concern related to system, equipment, entity, and human performance that may indicate a need to develop remediation strategies, action plans, or data used to revise or retire reliability standards or consider new reliability standards. The department analyzes and determines the cause of the events, promptly ensures tracking of corrective actions to prevent recurrence, and provides lessons learned to the industry. Event Analysis ensures that reporting and analysis are consistent to allow wide-area assessment of trends and risks. The department analyzes all reportable events for sequence of events, root cause, risk to reliability, and mitigation and keeps the industry well informed of system events, emerging trends, risk analysis, lessons learned, and expected actions.

Additional resources within this department focus on identifying human-error risks and those precursor factors that allow human error to impact system reliability. The department educates industry regarding risks, precursors, and mitigation methods. Resources also support compliance and standards training initiatives and trending and analysis to identify emerging reliability risks to the BES. These efforts are conducted in collaboration with industry human performance projects, including WECC's Human Performance Working Group, the NERC Operating Committee's Event Analysis Subcommittee, and others.

Stakeholder Engagement and Benefit

The Event Analysis department coordinates event analyses to support the use of collective resources, consistency in analysis, and timely delivery of event analysis reports.[29] The ERO disseminates to the electric industry lessons learned and other useful information obtained from or as a result of event analysis. The Event Analysis team conducts in-depth analyses of approximately 150 events per year on average. In 2014, the team also conducted calls facilitated by the Regional Entities with over 140 registered entities to discuss in detail and finalize root and contributing causes for the categorized events analyzed. Major analysis to date includes continuing assessment of Energy Management System (EMS) outages, continued collaboration with Reliability Assessments and System Analysis on frequency response performance, analyses of substation equipment failure events and protective relay trends including ground overcurrent relay misoperations, relay communication system failures, and the importance of commissioning testing.

Collaboration with the Trade Associations and Forums

The activities of the NATF, the NAGF, trade associations, and other industry groups are expected to compliment ERO Enterprise activities and limit the need to add incremental resources to the NERC and

[29] The core process for Event Analysis is outlined in the approved process: Electric Reliability Organization Event Analysis Process - Version 3 (January 2016).

Regional Entity business plans and budgets that might otherwise be required in the absence of these forums.

NERC is supporting the NAGF's ongoing transformation into a more formal structure through 2017 and continuing through 2018 with logistical and administrative support.

NATF has been invited to participate in several reliability initiatives that are expected to continue into 2017, including protection systems misoperations reduction, physical security, various activities related to reliability assurance initiatives, improvement of modeling practices, and complementary efforts on addressing the GMD challenges.

2017 Goals and Deliverables

In 2017, the Event Analysis department will seek to accomplish several specific goals and objectives as part of the strategic focus of the ERO Enterprise:

- Work with the Regional Entities to obtain and review information from registered entities on qualifying events and disturbances to advance awareness of events above a threshold level; facilitate analysis of root and contributing causes, risks to reliability, wide-area assessments, and remediation efforts; and disseminate information regarding events in a timely manner.
- Ensure that all reportable events are analyzed for sequence of events, root cause, risk to reliability, and mitigation.
- Continue to refine risk-based methods to support better identification of reliability risks, including the use of more sophisticated cause codes for analysis.
- Conduct training (webinars, workshops, and conference support) to inform industry and the ERO of lessons learned, root cause analysis, trends, human performance, and extreme weather preparedness and recommendations.
- Develop reliability recommendations and alerts as needed and track industry accountability for critical reliability recommendations.
- Ensure that industry is well informed of system events, emerging trends, risk analysis, lessons learned, and expected actions.
- Conduct major event analysis and reporting of major findings and recommendations that will improve reliability.

The Event Analysis department will also support several of the top-priority reliability risk projects during 2017 through 2018, as identified and described under the Performance Analysis department section of this document.

Resource Requirements

Personnel

The slight increase in FTEs budgeted in the Event Analysis department in 2017 is due to a lower vacancy rate than in 2016.

Contractor Expenses

No contractor expenses are budgeted in 2017.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
EVENT ANALYSIS

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 5,181,136	$ 5,181,136	$ 0	$ 5,300,955	$ 119,819	$ 5,370,925	$ (69,970)
Penalty Sanctions	134,385	$ 134,385		104,970	(29,415)	104,144	826
Total NERC Funding	**$ 5,315,521**	**$ 5,315,521**	**$ 0**	**$ 5,405,926**	**$ 90,404**	**$ 5,475,069**	**$ (69,143)**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	40,000	78,073	38,073	40,000	-	40,000	-
Interest	274	2,918	2,644	281	7	279	2
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 5,355,795**	**$ 5,396,512**	**$ 40,717**	**$ 5,446,206**	**$ 90,411**	**$ 5,515,347**	**$ (69,141)**
Expenses							
Personnel Expenses							
Salaries	$ 1,716,263	$ 1,617,447	$ (98,817)	$ 1,708,049	$ (8,214)	$ 1,778,729	(70,680)
Payroll Taxes	114,132	$ 110,186	(3,946)	108,739	(5,393)	117,316	(8,577)
Benefits	202,259	$ 183,405	(18,853)	212,232	9,973	213,883	(1,651)
Retirement Costs	191,377	$ 180,295	(11,082)	189,397	(1,980)	202,216	(12,819)
Total Personnel Expenses	**$ 2,224,030**	**$ 2,091,333**	**$ (132,698)**	**$ 2,218,416**	**$ (5,614)**	**$ 2,312,144**	**(93,727)**
Meeting Expenses							
Meetings	$ 81,500	$ 140,000	$ 58,500	$ 81,500	$ -	$ 81,500	-
Travel	152,487	152,000	(487)	152,487	-	152,487	-
Conference Calls	14,000	14,000	-	4,270	(9,730)	4,270	-
Total Meeting Expenses	**$ 247,987**	**$ 306,000**	**$ 58,013**	**$ 238,257**	**$ (9,730)**	**$ 238,257**	**-**
Operating Expenses							
Consultants & Contracts	$ 56,000	$ 56,000	$ -	$ -	$ (56,000)	$ -	-
Office Rent	-	-	-	-	-	-	-
Office Costs	49,181	53,576	4,395	49,634	452	49,538	96
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	72,367	85,582	13,214	85,582	13,214	85,582	-
Total Operating Expenses	**$ 178,048**	**$ 195,658**	**$ 17,609**	**$ 135,715**	**$ (42,333)**	**$ 135,619**	**$ 96**
Total Direct Expenses	**$ 2,650,065**	**$ 2,592,990**	**$ (57,075)**	**$ 2,592,388**	**$ (57,677)**	**$ 2,686,020**	**$ (93,631)**
Indirect Expenses	**$ 2,605,551**	**$ 2,511,155**	**$ (94,396)**	**$ 2,748,677**	**$ 143,126**	**$ 2,716,375**	**$ 32,302**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 5,255,616**	**$ 5,104,145**	**$ (151,471)**	**$ 5,341,065**	**$ 85,449**	**$ 5,402,394**	**$ (61,329)**
Change in Assets	**$ 100,179**	**$ 292,367**	**$ 192,188**	**$ 105,141**	**$ 4,962**	**$ 112,953**	**(7,812)**
Fixed Assets							
Depreciation	(72,367)	(85,582)	(13,214)	(85,582)	(13,214)	(85,582)	-
Computer & Software CapEx	-	-	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 172,546	$ 130,463	(42,083)	190,723	18,176	$ 198,535	(7,812)
Inc(Dec) in Fixed Assets (C)	**$ 100,179**	**$ 44,881**	**$ (55,298)**	**$ 105,141**	**$ 4,962**	**$ 112,953**	**$ (7,812)**
TOTAL BUDGET (=B + C)	**$ 5,355,795**	**$ 5,149,026**	**$ (206,769)**	**$ 5,446,206**	**$ 90,411**	**$ 5,515,347**	**$ (69,141)**
FTEs	**11.06**	**10.29**	**(0.77)**	**11.28**	**0.22**	**11.30**	**(0.02)**

Electricity Information Sharing and Analysis Center (E-ISAC)[30]

E-ISAC (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget - Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	18.90	19.74	0.84	19.78	(0.04)
Direct Expenses	$ 11,965,349	$ 12,276,689	$ 311,340	$ 12,501,721	$ (225,032)
Indirect Expenses	4,450,914	4,810,185	359,271	4,753,175	57,009
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	351,262	1,428,467	1,077,205	442,103	986,364
TOTAL BUDGET	$ 16,767,525	$ 18,515,341	$ 1,747,816	$ 17,696,999	$ 818,342

Background and Scope

The Electricity Sector Information Sharing and Analysis Center (ES-ISAC) was formed in 1998 when the U.S. Secretary of Energy requested that NERC serve as the ISAC[31] for the Electricity Subsector.[32] This department was rebranded to the Electricity Information Sharing and Analysis Center (E-ISAC) in September 2015. The E-ISAC reduces cyber and physical risk to the Electricity Subsector across North America by providing unique insights, leadership, and coordination. The vision is to be the trusted, timely, actionable resource of grid risk information and analysis to enhance electricity reliability. The E-ISAC facilitates Electricity Subsector and cross-sector coordination regarding physical security and cybersecurity events affecting the BES.

Maintaining Separation from Compliance and Enforcement

Starting in February 2012, the Board of Trustees approved an E-ISAC Policy Statement that established a separation between the E-ISAC and NERC's compliance and enforcement program. In 2015, physical separation of the E-ISAC was completed. The company also has in place an E-ISAC Code of Conduct and Policy on the Role of the E-ISAC vis-à-vis NERC's Compliance Monitoring and Enforcement Program.

Key Efforts Underway

With industry support, in coordination with the Electricity Subsector Coordinating Council (ESCC) and its Member Executive Committee (MEC), senior management is committed to enhancing the effectiveness and capabilities of E-ISAC operations. These efforts include ongoing enhancement in organizational structure, operational and analytical capabilities, as well as the development of metrics to track the effectiveness of operations. Management will also take steps to improve the quality and value of E-ISAC products, including ongoing review of registered user needs.

During 2015, as part of a periodic review of companywide resource needs and resource allocation, NERC allocated additional resources to support the E-ISAC. Management recruited personnel to fill open positions, and recruited and appointed a senior vice president and chief security officer in charge of E-ISAC operations. Ongoing resource requirements consist primarily of personnel, contractors, consultants,

[30] In 2015, NERC combined its Critical Infrastructure Department (CID) into the E-ISAC for both operational and financial reporting purposes.

[31] The Information Security Analysis Center (ISAC) construct was conceived and operates under US Government authorities derived from Presidential Decision Directive 63, which was signed in 1998. The ISACs focus specifically on information sharing, analytics and sector activities directly related to the protection of critical infrastructure.

[32] Subsequent administrations have sought to continue and strengthen information sharing in other sectors by establishing other sector-specific ISACs. In 2013, the Department of Energy (DOE) again reaffirmed its desire for NERC to continue to operate the E-ISAC.

software, hardware and communications infrastructure to gather, analyze, and provide information regarding cyber and physical security threats.

In the fourth quarter of 2014 and with broad industry support, NERC also assumed management responsibility for the Cybersecurity Risk Information Sharing Program (CRISP). CRISP is a public-private partnership whose purpose is to facilitate the sharing of cyber threat information and to develop situation awareness tools that enhance the electricity sector's ability to identify, prioritize, and coordinate the protection of its critical infrastructure. CRISP provides critical infrastructure owners and operators the capability to voluntarily share cyber threat data, analyze this data, and receive machine-to-machine mitigation measures. Information-sharing devices that are installed on participants' networks send encrypted data to a CRISP analysis center operated by the Pacific Northwest National Labs (PNNL), which analyzes the data it receives and sends alerts and mitigation measures back to CRISP participants and the E-ISAC through secure communications. CRISP became fully operational in 2015. The E-ISAC will continue to work with PNNL, CRISP participants and E-ISAC registered users to strengthen program execution, including both quality and timeliness aspects of information sharing. The 2017 E-ISAC budget maintains the same percentage allocation of CRISP funding requirements from assessments and from CRISP participants as 2016. In connection with the growth of the program and related support needs from E-ISAC staff, the 2017 E-ISAC budget also reflects an increase in the number of budgeted E-ISAC FTEs allocated to support CRISP.

Resource Requirements

Personnel

As previously noted, in 2016 additional open budgeted resources were re-allocated to provide support to the E-ISAC[33], resulting in a net increase of 0.84 FTEs.

The E-ISAC staffing and organizational structure has recently been updated to reflect four primary focus areas (1) stakeholder engagement, (2) watch operations (3) cyber security analysis, and (4) physical security analysis. NERC's 2017 organization chart attached as Appendix 1 has been updated to reflect these changes and additional personnel on-boarded in 2016. The E-ISAC will continue to receive shared services support from NERC's corporate services departments (i.e. finance and accounting, IT, HR, legal and external affairs). Personnel providing such shared services will do so only in accordance with strict operating protocols governing access to and use of E-ISAC information as noted above.

Contract Expenses

The specific nature and need for contract support for the E-ISAC falls under three major categories: Program Level Support, Software and Services, and Events and Outreach. Each of these categories is discussed further below and Exhibit C sets forth the budget for each of these categories of expense.

Program Level Support

CRISP

During 2016 and 2017 NERC will continue to subcontract to PNNL the majority of the resource requirements and associated costs to operate and maintain CRISP.

E-ISAC Portal Enhancement

The E-ISAC communication portal capabilities include: publishing immediate notifications and other informational products, exchanging threat indicator information, and providing self-service access to user

[33] Departments with reduced staffing needs included the legal, enforcement and standards departments.

security awareness services. The E-ISAC is working with NERC Information Technology (in the lead) to continue development of the portal that was initiated in 2014 as part of a long-term improvement strategy. Important new enhancements and improved capabilities are presently in use and development. These include facilitating direct data exchange with E-ISAC members, other ISACs and government partners, and establishing user communities where individuals can discuss security issues. The portal's improved capabilities support E-ISAC analysts in their information analysis functions and directly tie them with their counterparts in other sectors and national laboratories.

In 2015, the ESCC presented its recommendations resulting from a review of the E-ISAC operations performed that year. These recommendations included a request to evaluate and potentially enhance the user interface and underlying functionality of the E-ISAC portal. In 2015, the ESCC established a Member Executive Committee (MEC) to provide guidance with respect to various E-ISAC matters, including improvements to the E-ISAC portal. As part of an approved 2016 work plan, the E-ISAC staff worked closely with the MEC to develop a business case and funding estimates for these improvements. Additional details summarizing the business case, funding estimate and additional detail regarding the portal improvement project is attached as Exhibit F.

The 2017 E-ISAC budget includes $1M for the portal enhancements ($250,000 of which is allocated to CRISP)[34]. The MEC has provided written comments [found here] in support of this investment.

Additional portal enhancements in 2016 and 2017 will also extend functionality to allow for easier access to filtered data for both the cyber and physical security communities and provide for automated information sharing. Based on input from users, the E-ISAC is transitioning the current portal capability to a platform model that will provide features and extensions beyond what can currently be delivered with the existing portal. Some of the new features will include user customization, visual and graphical orientation (versus text-based), robust search and structured queries, and the ability to create on-the-fly technical analysis of information shared by users. This will be a multi-year project that will evolve as users engage the new capabilities and provide feedback. In 2017 the E-ISAC and NERC IT plan to launch the initial platform prototype with new capabilities, then add capabilities and features in 2018 and subsequent years as needed.

Software and Services

Software Integration Support Services

The E-ISAC operations center includes monitors used to display intelligence information provided from various software applications. Software integration services are routinely required from vendors providing existing and new software applications. Additional software must be licensed and maintained to display and integrate BES maps that have cyber intelligence information. A portion of these costs is budgeted under Office Costs as software maintenance expenses.

Analyst Workbench

A strong technical analytic capability is needed to develop baselines and identify patterns and understandings of potential cyber-related threats. The analyst workbench toolset maintains historical information and allows a team to use and deliver consistent and repeatable analysis in both an operational (during an event) as well as nonoperational capacity. This workbench will include a threat database for historical correlation and various tools for network- and host-based analysis of malicious software.

[34] The annual impact of the proposed $1M investment on assessments will be approximately $250,000 since projects of this nature are typically financed through NERC's capital financing program and funded over a three year period.

Automated Information Sharing

The E-ISAC is broadening automated information sharing beyond CRISP, looking at programs such as the Structured Threat Information Expression/Trusted Automated Exchange of Indicator Information (STIX/TAXII) initiative hosted by the US Department of Homeland Security. As part of a work plan developed in consultation with the MEC, in 2016 the E-ISAC plans to pilot and gather data on these technologies, leveraging existing implementations at Argonne National Lab. The pilot will help the E-ISAC understand the nuances of bi-directional communication, workflow, handling rules, vetting information, and learning from the technology and processes overall. The E-ISAC aims to have seven members signed up by the end of 2016, and, assuming the 2016 pilot is successful, another 10 members sign up in by the end of 2017.

Events and Outreach

Grid Security Exercises

Since 2011, NERC has sponsored a series of biennial grid security exercises (GridEx). These geographically distributed exercises are designed to exercise the electricity sector's crisis response to simulated coordinated cybersecurity and physical security threats and incidents, to strengthen utilities' crisis response functions, and to provide input for lessons learned. GridEx III, in November 2015, consisted of a two-day grid-focused operational exercise for participants across North America and a half-day tabletop discussion for executives. The E-ISAC manages the program and collects industry information during and after the exercise subject to existing data collection policies. During the exercise, E-ISAC watch and analysis staff exercise the E-ISAC mission and share severe crisis information sharing and analysis towards mitigating the threats and attacks. Lessons learned and recommendations are turned over to groups like NERC's Board of Trustees and CIPC and to the ESCC for consideration and coordination between industry and government stakeholders. GridEx IV is scheduled for November 15-16, 2017.

Grid Security Conferences

Since 2011, NERC has sponsored a series of annual grid security conferences (GridSecCon). These conferences bring together industry and government subject matter experts on cyber, physical and operations technology threats and solutions, with training sessions and classified or official use briefs on topics vital to grid security. The E-ISAC provides expertise and gathers appropriate speakers, panelists and training providers. GridSecCon 2016 is scheduled for October 18-21 in Quebec, Canada, with the 2017 location and dates TBD.

Intelligence Reporting Services

E-ISAC analytic personnel maintain a detailed understanding of emerging vulnerabilities and threats within the broad industrial control systems community, as well as within the more focused BES community. To support this intelligence role, the E-ISAC budget includes the costs for intelligence services from a specialized security information service providers that focuses closely on the electricity subsector. This service gives E-ISAC staff increased understanding of continuing trends, breaking news, and implications to the BES, which they utilize to keep registered entities informed of emerging BES risks through immediate notifications and portal security postings.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection and 2017 Budget
E-ISAC

	2016 Budget	2016 Projection	2016 Projection v 2016 Budget Over(Under)	2017 Budget	2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 9,636,756	9,636,756	$ (0)	$ 11,270,705	$ 1,633,948	$ 10,533,578	$ 737,127
Penalty Sanctions	229,563	229,563	0	183,698	(45,865)	182,233	1,465
Total NERC Funding	**$ 9,866,319**	**$ 9,866,319**	**$ (0)**	**$ 11,454,403**	**$ 1,588,084**	**$ 10,715,811**	**$ 738,592**
Third-Party Funding (CRISP)	6,830,738	7,335,757	505,019	6,990,447	159,709	6,910,701	79,746
Workshops	70,000	70,000	-	70,000	-	70,000	-
Interest	468	-	(468)	491	24	487	4
Total Funding (A)	**$ 16,767,525**	**$17,272,076**	**$ 504,551**	**$ 18,515,341**	**$ 1,747,816**	**$ 17,696,999**	**$ 818,342**
Expenses							
Personnel Expenses							
Salaries	$ 3,373,066	$ 3,242,857	$ (130,209)	$ 3,417,398	$ 44,332	$ 3,391,165	$ 26,234
Payroll Taxes	208,610	193,941	(14,668)	204,023	(4,587)	209,345	(5,322)
Benefits	345,260	315,363	(29,897)	397,467	52,207	384,714	12,754
Retirement Costs	366,723	351,531	(15,192)	363,482	(3,241)	372,179	(8,697)
Total Personnel Expenses	**$ 4,293,659**	**$ 4,103,693**	**$ (189,966)**	**$ 4,382,370**	**$ 88,711**	**$ 4,357,402**	**$ 24,968**
Meeting Expenses							
Meetings	$ 230,000	$ 229,000	$ (1,000)	$ 230,000	$ -	$ 230,000	$ -
Travel	256,488	237,455	(19,032)	256,488	-	256,488	-
Conference Calls	22,000	23,000	1,000	6,710	(15,290)	6,710	-
Total Meeting Expenses	**$ 508,488**	**$ 489,455**	**$ (19,032)**	**$ 493,198**	**$ (15,290)**	**$ 493,198**	**$ -**
Operating Expenses							
Consultants & Contracts	$ 6,551,929	$ 7,579,159	$ 1,027,230	$ 6,788,429	$ 236,500	$ 7,038,429	$ (250,000)
Office Rent	-	$ -	-	-	-	-	-
Office Costs	392,285	$ 296,103	(96,182)	431,895	39,610	431,895	-
Professional Services	175,000	$ 175,000	-	175,000	-	175,000	-
Miscellaneous	500	$ 500	-	500	-	500	-
Depreciation	43,489	$ 45,998	2,509	5,297	(38,192)	5,297	-
Total Operating Expenses	**$ 7,163,203**	**$ 8,096,760**	**$ 933,557**	**$ 7,401,121**	**$ 237,919**	**$ 7,651,121**	**$ (250,000)**
Total Direct Expenses	**$ 11,965,349**	**$12,689,908**	**$ 724,559**	**$ 12,276,689**	**$ 311,340**	**$ 12,501,721**	**$ (225,032)**
Indirect Expenses	**$ 4,450,914**	**$ 4,601,898**	**$ 150,984**	**$ 4,810,185**	**$ 359,271**	**$ 4,753,175**	**$ 57,009**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 16,416,263**	**$17,291,806**	**$ 875,543**	**$ 17,086,873**	**$ 670,610**	**$ 17,254,896**	**$ (168,023)**
Change in Assets	**$ 351,262**	**$ (19,730)**	**$ (370,992)**	**$ 1,428,467**	**$ 1,077,205**	**$ 442,103**	**$ 986,364**
Fixed Assets							
Depreciation	(43,489)	(45,998)	(2,509)	(5,297)	38,192	(5,297)	-
Computer & Software CapEx	100,000	111,722	11,722	1,100,000	1,000,000	100,000	1,000,000
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	41,958	41,958	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 294,751	$ 248,373	(46,378)	333,765	39,014	347,401	(13,636)
Inc(Dec) in Fixed Assets (C)	**$ 351,262**	**$ 356,054**	**$ 4,792**	**$ 1,428,467**	**$ 1,077,205**	**$ 442,103**	**$ 986,364**
TOTAL BUDGET (=B + C)	**$ 16,767,525**	**$17,647,860**	**$ 880,335**	**$ 18,515,341**	**$ 1,747,816**	**$ 17,696,999**	**$ 818,342**
FTEs	**18.90**	**18.95**	**0.05**	**19.74**	**0.84**	**19.78**	**(0.04)**

Training, Education, and Operator Certification

Training, Education and Operator Certification (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	7.38	7.05	(0.33)	7.07	(0.01)
Direct Expenses	$ 2,062,086	$ 1,922,295	$ (139,791)	$ 1,889,814	$ 32,481
Indirect Expenses	1,737,034	1,717,923	(19,111)	1,697,734	20,189
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	113,112	117,283	4,171	122,165	(4,882)
TOTAL BUDGET	$ 3,912,231	$ 3,757,501	$ (154,731)	$ 3,709,713	$ 47,788

Background and Scope

NERC's Training and Education Program provides oversight and coordination of the delivery of training programs that support the ERO's statutory responsibilities. This program provides training to NERC and Regional Entity staff members. It also provides training and education to industry participants on the requirements of reliability standards and the compliance monitoring and enforcement process. Further, this program provides training to industry participants on NERC's reliability standards development process, thereby helping to support the more efficient and effective development of mandatory reliability standards. The Training and Education Program supports NERC's responsibilities to develop, adopt, and obtain approval of reliability standards and to monitor, enforce, and achieve compliance with the mandatory standards. Section 901 of the NERC Rules of Procedure addresses the Training and Education Program's activities. The responsibility for training is shared among multiple departments at NERC.[35]

NERC's System Operator Certification program, which ensure that personnel operating the BES have the skills, training, and qualifications needed to operate the system reliably. NERC maintains the required credentials for over 6,000 system operators to work in system control centers across North America. NERC's system operator certification exam is designed to test specific knowledge of job skills and reliability standards. It also prepares operators for complying with requirements of reliability standards and appropriately operating the BES during normal and emergency operations. The System Operator Certification Program is governed by the Personnel Certification Governance Committee (PCGC), an industry group of operations experts, trainers, and supervisors. Certification exams are created by the Exam Working Group (EWG), an industry group of operations subject matter experts. Under the PCGC oversight, the EWG reviews and updates job tasks and certification exams. Section 600 of the NERC Rules of Procedure addresses the Personnel Certification activities in the area of Operator Certification.

Once an operator passes the certification exam, certification is maintained by completing NERC-approved continuing education courses and activities. The Personnel Subcommittee, composed of industry training experts, provides oversight of the Continuing Education program. Section 902 of the NERC Rules of Procedure addresses the Continuing Education Program's activities in these areas.

Key Efforts Underway

The ERO provides education for industry and ERO Enterprise staff personnel to support their understanding of key program areas. These areas include:

[35] The Human Resources department is also engaged in training initiatives.

1. Risk-Based Compliance Monitoring and Enforcement
2. Standards and Compliance
3. Registration and Certification
4. Event Analysis, Cause Analysis, and Lessons Learned
5. Reliability Assessment and System Analysis
6. Continuing education for system operators
7. New System Operator Certification exams for each credential: Reliability Coordinator; Transmission Operator; Balancing and Interchange Operator; and Balancing, Interchange and Transmission Operator.

2017 Goals and Deliverables

In response to stakeholder and Regional Entity feedback, training and education opportunities will be further expanded and focused for registered entities, NERC staff, and Regional Entities. For registered entities, this training and education will focus on objectives related to NERC reliability standards, including standards compliance and emerging cyber-related issues that could affect BES reliability. For NERC and Regional Entity staff, the training and education will focus on consistent audit and investigation techniques and standards compliance reviews, including the risk-based compliance monitoring and enforcement and other improvements in compliance and enforcement practices. NERC will continue to offer training in auditor skills to promote continued development of auditing expertise. NERC will leverage IT systems to better deliver and share common training products and information with Regional Entities and registered entities. Other training will focus on knowledge and skill development in a number of key areas, including:

- Development and implementation of clear and technically sound reliability standards
- Key lessons learned and trends from events
- Identified themes from trending and common-cause analyses
- Effective compliance cultures with practices, procedures, and controls to address reliability risks
- Effective root, apparent, and common-cause analysis methods
- Quality improvement of registered entity self-reporting and self-certification
- Entity registration processes, issues, and alternatives
- Human performance fundamentals
- Developing and incorporating a systematic approach to ongoing training

NERC will continue to provide learning opportunities through workshops hosted by the Regional Entities. NERC will also host workshops, webinars, and training courses, as well as use vendors to develop training modules and supplement internal training resources. The responsibility for the subject matter expertise for much of the training is shared among multiple departments at NERC. The Training and Education group will provide coordination and synchronization efforts for shared NERC and ERO training responsibilities in addition to advancing and improving the skills of NERC's operating staff. NERC's Human Resources department will continue to budget and manage the delivery of more traditional corporate employee training and continuing education programs in concert with the coordination and synchronizing efforts of the Training and Education group.

As part of the System Operator Certification exam development cycle, the results of the 2015 job task analysis (JTA) is the baseline for the upcoming set of exams. The EWG will continue to analysis new items and develop a cut score for the pending 2018 exams.

Key deliverables for the System Operator Certification Program:

- Complete analysis of exam Item Bank
- Implementation of Linear On the Fly (LOFT) testing for all exams

NERC will continue to work with industry stakeholders and the exam development vendor to create certification exams that will promote reliability of the North American BPS.

The Continuing Education (CE) program will evaluate and revise the current program criteria as reflected in the program manual. The evaluation will consider the growth and maturation of industry training programs as well as ongoing research in the area of adult learning to ensure the CE program continues to foster improvement of training and promotes quality in training programs.

Resource Requirements

Personnel
No additional personnel are proposed for this area in 2017.

Contractor Expenses
The total proposed consulting and contractor budget is approximately $95k lower in 2017 than the 2016 budget.

Further detail in support of the proposed 2017 contractor and consulting budget to support Training, Education, and Operator Certification is set forth in Exhibit C, which includes a comparison to 2016 budgeted amounts. The primary areas of contractor and consulting support include:

- Testing services to develop, administer, proctor, score, and support system operator certification exams across North America.
- Ongoing hosting and maintenance fees for the System Operator Certification and Continuing Education (SOCCED) database.
- Improvements to the SOCCED database.
- Supplemental support to Continuing Education Review Panel industry volunteers to review and audit over 2,500 individual learning activities and provider applications received each year.[36]
- Audit team leader soft skills training delivered by certified NERC staff using vendor-licensed materials to support effective dialogue and communications between audit teams and registered entities.
- Vendor-supported BES technical training for select ERO staff, including compliance, technical and support staff.
- Risk-based compliance training by recognized specialists for NERC and Regional Entity staff to promote continued development of compliance staff.

[36] Review and approval of learning activity applications results in over 400,000 hours of continuing education per year for the industry's certified system operators.

- Web-based training development for ERO staff and industry, including standards applications, risk assessment training, industry human performance fundamentals, and BES events lessons learned.
- An ERO Enterprise learning management system to support scheduling, computer-based training delivery and record maintenance for ERO and select Enterprise staff.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
TRAINING, EDUCATION and OPERATOR CERTIFICATION

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 1,742,146	$ 1,742,146	$ 0	$ 1,822,089	$ 79,944	$ 1,820,199	$ 1,890
Penalty Sanctions	55,994	55,994	$ -	43,738	(12,256)	43,393	344
Total NERC Funding	**$ 1,798,139**	**$ 1,798,139**	**$ 0**	**$ 1,865,827**	**$ 67,687**	**$ 1,863,592**	**$ 2,235**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	1,867,972	1,867,972	-	1,921,900	53,928	1,921,900	-
Services & Software	-	-	-	-	-	-	-
Workshops	-	-	-	-	-	-	-
Interest	183	2,096	1,913	175	(7)	174	1
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 3,666,294**	**$ 3,668,207**	**$ 1,913**	**$ 3,787,902**	**$ 121,608**	**$ 3,785,666**	**$ 2,236**
Expenses							
Personnel Expenses							
Salaries	$ 857,257	$ 849,104	$ (8,153)	$ 852,091	$ (5,166)	$ 845,520	6,570
Payroll Taxes	64,345	65,293	948	62,727	(1,619)	63,717	(990)
Benefits	133,991	114,786	(19,205)	139,239	5,248	116,375	22,864
Retirement Costs	94,860	97,129	2,268	97,624	2,764	98,587	(963)
Total Personnel Expenses	**$ 1,150,454**	**$ 1,126,312**	**$ (24,142)**	**$ 1,151,681**	**$ 1,227**	**$ 1,124,199**	**27,481**
Meeting Expenses							
Meetings	$ 80,000	$ 55,000	$ (25,000)	$ 55,000	$ (25,000)	$ 55,000	-
Travel	21,139	19,900	(1,239)	21,139	-	21,139	-
Conference Calls	36,500	36,500	-	11,133	(25,368)	11,133	-
Total Meeting Expenses	**$ 137,639**	**$ 111,400**	**$ (26,239)**	**$ 87,272**	**$ (50,368)**	**$ 87,272**	**-**
Operating Expenses							
Consultants & Contracts	$ 675,800	$ 731,460	$ 55,660	$ 580,600	$ (95,200)	$ 580,600	-
Office Rent	-	-	-	-	-	-	-
Office Costs	95,773	104,935	9,161	100,323	4,550	95,323	5,000
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	1,919	1,919	-	1,919	-	1,919	-
Total Operating Expenses	**$ 773,992**	**$ 838,814**	**$ 64,821**	**$ 683,342**	**$ (90,650)**	**$ 678,342**	**$ 5,000**
Total Direct Expenses	**$ 2,062,086**	**$ 2,076,525**	**$ 14,440**	**$ 1,922,295**	**$ (139,791)**	**$ 1,889,814**	**$ 32,481**
Indirect Expenses	**$ 1,737,034**	**$ 1,810,570**	**$ 73,536**	**$ 1,717,923**	**$ (19,111)**	**$ 1,697,734**	**$ 20,189**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 3,799,119**	**$ 3,887,096**	**$ 87,976**	**$ 3,640,218**	**$ (158,901)**	**$ 3,587,548**	**$ 52,670**
Change in Assets	**$ (132,825)**	**$ (218,888)**	**$ (86,063)**	**$ 147,684**	**$ 280,510**	**$ 198,118**	**(50,434)**
Fixed Assets							
Depreciation	(1,919)	(3,838)	-	(1,919)	-	(1,919)	-
Computer & Software CapEx	-	-	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 115,031	$ 103,360	(11,671)	119,202	$ 4,171	$ 124,084	(4,882)
Inc(Dec) in Fixed Assets (C)	**$ 113,112**	**$ 99,522**	**$ (11,671)**	**$ 117,283**	**$ 4,171**	**$ 122,165**	**$ -**
TOTAL BUDGET (=B + C)	**$ 3,912,231**	**$ 3,986,618**	**$ 76,305**	**$ 3,757,501**	**$ (154,731)**	**$ 3,709,713**	**$ 47,788**
FTEs	**7.38**	**7.39**	**0.01**	**7.05**	**(0.33)**	**7.07**	**(0.01)**

Administrative Services

Administrative Services (in whole dollars)	Direct Expenses and Fixed Assets			FTEs						
	2016 Budget	2017 Budget	Increase (Decrease)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget - Prior Draft	Draft Over(Under)	2017 FTE -Prior Draft	Prior Draft Over(Under)
General and Administrative	$ 9,881,311	$ 10,205,977	$ 324,666	17.52	16.92	(0.60)	10,048,346	157,631	16.01	0.91
Legal and Regulatory	3,465,966	3,292,379	(173,587)	12.22	11.28	(0.94)	$ 3,370,002	(77,623)	12.25	(0.97)
Information Technology	12,156,674	12,480,846	324,171	22.13	23.27	1.14	$ 12,448,188	32,658	23.31	(0.05)
Human Resources	1,510,177	1,608,583	98,406	2.77	2.82	0.05	$ 1,684,684	(76,102)	3.77	(0.95)
Finance and Accounting	3,428,307	3,827,050	398,743	16.60	15.04	(1.56)	$ 3,844,269	(17,219)	16.01	(0.97)
Total Administrative Services	**$ 30,442,435**	**$ 31,414,834**	**$ 972,399**	**71.23**	**69.33**	**-1.91**	**$ 31,395,489**	**19,345**	**71.36**	(2.03)

Program Scope and Functional Description

NERC's Administrative Services area includes the budget for all business and administrative functions of the organization, including (1) technical committees and member forums; (2) General and Administrative, which includes Board fees and expenses, the president and chief executive officer (CEO), chief reliability officer (CRO) and support staff, communications, external affairs and governmental relations, and office rent; (3) Legal and Regulatory; (4) Information Technology; (5) Human Resources; (6) Finance and Accounting; and (7) other general administrative expenses necessary to support program area activities. These functions are necessary to the existence and functioning of the organization and support the performance of NERC's ERO statutory activities. The costs of the Administrative Services functions are allocated to the five statutory programs as indirect expenses. The resource requirements and comparative budget information for each of these functions are described below.

Technical Committees and Members' Forum Program

While NERC management and staff will continue to interact with and support numerous reliability-related forums (e.g., the North American Transmission Forum and Generator Forum), NERC's 2017 budget does not contain specific funding for any forum activities.

General and Administrative

Background and Scope

The General and Administrative area is responsible for the administration and general management of the organization. Expenses allocated in this area include office rent; personnel and related costs of the CEO, the CRO, the CEO's executive assistant, communications, external affairs and government relations staff, and costs related to the Board. No additional personnel are budgeted for 2017 beyond current staffing. The increase in FTEs in the General and Administrative area is due to a reallocation occurring in 2016 of personnel supporting the Member Representatives Committee and Regional Entity Management Group activities.

The following table details the Board costs included in the total costs of the General and Administrative area.

Board of Trustee Expenses	Budget 2016	Projection 2016	Budget 2017	2017 v 2016 Budget	Variance %
Meetings and Travel Expenses					
Quarterly Board Meetings	$ 244,000	$ 244,000	$ 244,000	$ -	
Trustee Travel	150,000	150,000	150,000	-	
Total Board of Trustees Meetings and Travel Expenses	**$ 394,000**	**$ 394,000**	**$ 394,000**	**$ -**	
Professional Services				-	
Independent Trustee Fees	$ 1,126,354	$ 1,126,354	$ 1,226,000	$ 99,646	
Trustee Search Fees	100,000	100,000	100,000	-	
Total Board of Trustee Professional Services Expenses	**$ 1,226,354**	**$ 1,226,354**	**$ 1,326,000**	**$ 99,646**	**8.13%**
Total Board of Trustee Expenses	**$ 1,620,354**	**$ 1,620,354**	**$ 1,720,000**	**$ 99,646**	**6.15%**

Legal and Regulatory

Background and Scope

The Legal and Regulatory department's workload is derived from the following key NERC program areas: Compliance Analysis and Certification and Registration, Reliability Risk Management, Reliability Assessment and Performance Analysis, and Standards. In addition, the Legal and Regulatory department is also responsible for providing a wide range of legal support to the NERC management team regarding antitrust, corporate, commercial, insurance, contract, employment, real estate, copyright, tax, legislation, and other legal matters. The department also addresses legal and regulatory matters that arise in connection with the delegation agreements with the Regional Entities.

Resource Requirements

Due to process improvements and increased efficiency, the number of FTEs allocated to the department was reduced in 2017 compared to 2016.

Outside law firms and consultants supporting this area are budgeted and tracked as Professional Services. The Professional Services budget for 2017 was reduced by approximately 25% compared to the 2016 budget.

Information Technology

Background and Scope

NERC's IT department plan includes capital and operating expenses required to support, build, configure, and enhance applications that serve registered entities, Regional Entities, and NERC staff. The plan also includes work related to ERO Enterprise data analysis, as well as ongoing NERC internal operations.

The focus of the 2017 – 2019 budget places a heavy emphasis on applications and data analytics designed to improve and enhance the efficiency and productivity of NERC and the Regional Entities, and support more consistent and streamlined interactions with registered entities. These investments will provide broad benefits across the ERO Enterprise in terms of the efficiency and effectiveness of operations and meeting our reliability goals. Additionally, by working to provide more services to the Regional Entities in terms of tools and systems, associated economies of scale will result in these initial investments providing increasing value across the ERO Enterprise in the years to come.

The budget is broken down into four categories as follows:

1. **ERO Enterprise New Functionality –** Items listed in this category are those items designed to add, enhance, or improve, capabilities for registered entities, Regional Entities, and NERC staff. This includes items such as Enterprise Reporting, data analytics and warehousing, the Misoperation

Information Data Analysis System (MIDAS), User Management and Registration (UMR), and the Generating Availability Data System for Wind Turbine Generation (GADS Wind).

2. **ERO Enterprise Infrastructure & Support –** Items listed in this category are those infrastructure and support items required for applications used by registered entities, Regional Entities, and NERC staff. Items include The Events Analysis Management System (TEAMS), the Bulk Electric System Notification and Exception System tool (BESnet), the Standards Balloting System (SBS), the Reliability Coordinator Information System (RCIS), and numerous other applications.
3. **NERC New Functionality –** Items in this category are those items that enhance or improve the internal NERC infrastructure, such as Document Management, telephony, and audio visual.
4. **NERC Infrastructure & Support –** Items listed in this category are primarily those items required to maintain and run the internal office infrastructure, and support NERC staff operations. Items include server hardware and software licenses, network equipment, data and telecommunication circuits, and data storage, as well as office administrative applications (e.g., Microsoft Office) and user hardware such as laptops and peripherals.

A further discussion of each item is outlined below:

ERO Enterprise New Functionality:
As noted above, this category is primarily those applications or systems designed to improve or add capability to registered entities, Regional Entities, and NERC staff. Over the past two years, IT has been successful at deploying a number of new applications and functionality for the ERO Enterprise that have now moved into support. In 2017 and beyond, IT will continue that trend with a heavy focus on data and analytics.

a. Enterprise Reporting. In 2015, IT was successful at providing Enterprise Reporting Phase 1 and 2. In the latter part of 2016, IT will bring generation performance data into the Enterprise Reporting system. In 2017 and subsequent budget planning years IT will focus on additional datasets, as well as increasing the analytical and data mining capabilities for the ERO Enterprise.

b. Entity Registration. In 2016, IT began an effort to replace its existing "User Management Program" customer relationship management tool with one based on Microsoft Dynamics CRM (xRM). In 2017, that effort will be extended by integrating the compliance registration function into the xRM system, including implementation of the "common registration form." This will result in a common registration system shared across the ERO Enterprise that provides a consistent user experience for registered entities.

c. Compliance Monitoring and Enforcement Process Tools. IT will also work closely with the Regional Entities in 2017 to evaluate and implement strategic investments in tools that support the Compliance Monitoring and Enforcement Process. Items under consideration at this time include how NERC and the Regional Entities manage registered entity information (and how that information integrates with Enterprise Reporting to provide reliability risk analysis functionality), how Reliability Standards data is stored and maintained, and how best to support the various parts of the compliance and enforcement process (e.g., analysis of risk, development of implementation plans and audit schedules, actual compliance monitoring, and enforcement processing). Funding for any capital investments in new Enterprise Compliance and Monitoring Tools will be subject to review and approval as part of the business plan and budget application to the year when such investments are proposed to be made.

d. Extranet Development – NERC IT currently provides external collaboration function through the use of secure WebDAV folders and limited deployment of Microsoft SharePoint. In 2017, IT will

develop a more robust implementation of SharePoint to provide better services and support for collaboration across the ERO Enterprise and with stakeholders.

ERO Enterprise Infrastructure & Support:
This line item primarily consists of items used by registered entities, Regional Entities, and NERC Staff. During 2015, and 2016, IT, worked closely with the Regional Entities to design and configure a number of ERO Enterprise applications, with a bias toward using Commercial-off-the-Shelf (COTS) technology whenever possible. Infrastructure and support for these COTS tools (such as SharePoint and the Dynamics xRM platform), as well as custom built applications developed in the past, require ongoing investment to maintain continuous operations. For many applications and systems, this includes the cost of maintaining development, quality assurance, and staging and production environments, which are required to ensure the security and operational integrity and stability of the multiple applications supported for the ERO Enterprise. These applications and systems are monitored, tested (including penetration and vulnerability testing), and maintained in a manner as to ensure the highest level of integrity, security, and availability to the roughly 4,000 users across North America.

In 2016, IT placed emphasis on ensuring the environment was configured in a manner consistent with enterprise best practices, ensuring the security and integrity of the environment while allowing ERO Enterprise users to obtain the information and resources required to perform various analyses. Ongoing support for applications such as TEAMS, MIDAS, SBS, the Reliability Analysis Data System (RADS), in addition to numerous legacy ERO Enterprise products, make up this portion of the IT budget.

NERC New Functionality:
Items included in this category are primarily those items designed to improve, enhance, or replace existing functionality for internal NERC staff and, generally speaking, are not consumed by ERO Enterprise clients.

a. **Document Management Program and Intranet Enhancement** – During 2015 and 2016, NERC began implementation of a document management system, leveraging SharePoint 2013 as the foundational platform. The implementation of a document management program supports a number of important business requirements, including:

   - Ensuring proper classification and management of confidential information
   - Addressing a number of internal audit recommendations/mitigating corporate risk
   - Improving information access and search capabilities
   - Facilitating working group, team, and stakeholder collaboration
   - Supporting document retention policy and procedures
   - Simplifying document retrieval
   - Improving version control of documents
   - Improving workflow control (review and approval of documents)
   - Increasing efficiency and employee productivity

   Two additional products were integrated as part of this effort: Gimmal Compliance Suite, an add-on to SharePoint, which enables robust records management capabilities, and Repstor Affinity, which enables offline visibility into content repositories via Microsoft Outlook. In 2016, NERC will implement document management for six program areas. In 2017, NERC will bring the remaining program areas online. The implementation of a document management system is a multi-year initiative designed to greatly reduce the manual and labor-intensive

effort of managing thousands of documents by streamlining the storage, security, versioning, data classification, and archiving of NERC information.

b. **Audio Visual –** During 2016, IT will replace audit visual (AV) equipment in NERC's primary conference rooms with a Cisco WebEx solution designed to enhance capability (e.g. video conferencing), in addition to reducing cost of travel, when possible. In 2017, as appropriate and approved, additional conference rooms will be refreshed with AV equipment.

c. **IT Infrastructure Services** – During 2016, IT undertook an initiative to leverage qualified vendors for sourceable work, allowing IT to place a greater emphasis on ERO Enterprise projects. Network monitoring is one example of where we have been successful in moving items such as monitoring to a qualified vendor. While technically not "new" capability, implementation of this new approach to network monitoring allows NERC's internal IT resources to focus on larger initiatives designed to serve the ERO Enterprise. IT will continue to pursue this strategy in 2017 as additional work is identified that can be efficiency and cost effectively assumed by qualified vendors.

d. **Public Facing Website Improvements** - Over the past several years, NERC has routinely made updates to its outward-facing Internet presence, during which technology improvements are made and suggestions and requests are implemented. In 2017, IT will work with the company's communications department to begin a project to review the information architecture of the NERC.com site and make changes with the goal of providing a more streamlined user experience.

NERC Infrastructure & Support

As previously noted, NERC Infrastructure & Support are those items required to maintain and support the internal infrastructure for NERC staff. Items such as file servers, network equipment, storage, Microsoft Office (Word, Excel, PowerPoint, Email, SharePoint, etc.), along with security and telecommunications are required to ensure staff have the necessary tools and technology to perform their daily operational functions. Emphasis in 2017 and in the 2018 – 2019 planning cycle will continue to work toward optimizing the amount of effort placed on NERC infrastructure and support to minimize spend on internal office steady state operations, allowing a larger portion of IT resources to focus on new ERO Enterprise functionality, as well as ERO Enterprise infrastructure and support. Examples of items included in internal operations are outlined below**:**

a. **Compliance Reporting and Tracking System (CRATS)** – This compliance database is used to track violations, mitigation plans, and reporting required by NERC as the certified ERO. In addition, the compliance database has additional modules included, such as the Standards, Technical Feasibility Exceptions (TFEs), and Registration module, which contains a list of all registered entities. Funding requirements include ongoing maintenance and enhancements to the CRATS compliance tools.

b. **Meeting Manager, ERO Membership, RCIS, Central Repository of Curtailment Events (CRC)** – NERC maintains a number of legacy applications. Many of the legacy applications were developed and implemented five to ten years ago and are unable to benefit from contemporary application development. Some may have to be completely rewritten, or moved to the xRM application platform, as IT was able to do with Application Broker, NERC MyAccount and UMP in 2016. Funding in 2017 is required for ongoing maintenance and enhancements until the applications can be rewritten or moved to the xRM platform or, in some cases, potentially divested or transferred to industry support.

c. **Quarterly Penetration and Vulnerability Testing All NERC Networks and Systems** – Expert consulting services to provide ongoing intrusion detection and vulnerability testing of the

NERC public website, NERC's network, applications, and systems is an essential requirement of ongoing operations. NERC is subject to frequent intrusion attempts where external parties try to gain access to our systems and infrastructure. Any vulnerability identified is documented and provided to NERC IT for rapid remediation.

d. **NERC Security Program -** NERC's IT department performs a number of technology initiatives to ensure the security of the network and infrastructure. However, in order to continually improve security, a more holistic approach is required that implements technology improvements and constructs an overarching security program to ensure all aspects of security have been considered, including information classification, review of retention policies, and enforcement of security guidelines. During 2016, IT undertook an initiative to improve several processes and will continue to place a high emphasis on security over the coming years.

Robust Planning for New Capital Projects

In connection with the 2016 business planning cycle, the company significantly improved its approach to evaluating potential capital investments in major enterprise software applications. The company has adopted an enterprise information technology investment planning methodology that ensures only projects with compelling and approved business cases are funded. The approval process uses a four approval gates:

- A Business Unit Sponsor approval gate,
- A NERC VP/CTO approval gate,
- An ERO Technology Leadership Team (comprised of the NERC CEO and two Regional Entity CEOs) approval gate, and
- The full ERO-EMG (CEOs of NERC and each Regional Entities) approval gate.

This gated process provides the required rigor and discipline to ensure only high value enterprise IT investments are pursued. In addition, all Enterprise IT investments are subject to ongoing oversight by a subgroup consisting of four members of the Board's Standards Oversight and Technology Committee. The company will continue to use this process for the 2017 – 2019 budget planning cycle.

Examples of the results of this methodology in 2016 include investments in TEAMS and the RADS.

TEAMS. The TEAMS application provides integration of events data systems, while enabling a more efficient and effective method for event data collection, tracking, analysis and reporting. This enhances the ability of the ERO and stakeholders to identify and focus on significant and emerging reliability risks. This tool is used by NERC and the Regional Entities, providing a consistent experience for all ERO clients involved in the events analysis business process. The benefits provided by the TEAMS application streamline ERO Enterprise reliability data sources with an event data collection platform that is consistent with the event analysis process. Benefits include:

- **Improving Efficiency:** TEAMS helps ensure the reliability of the Bulk Power System by facilitating:
  - The reporting of a BPS event
  - The evaluation of BPS events
  - The undertaking of appropriate levels of EA
  - The generation of lessons learned

  - The generation of reliability trend analysis

- **Managing Reliability Risk:** TEAMS enables the ERO Enterprise to integrate event reports with other reliability data sources and develop portfolios of risk information. This integration enables a more complete analysis into the cause of events, including transmission outages, generation trips, and load loss. With this analysis, the ERO Enterprise can better identify unplanned service interruptions and spotlight key areas for reliability improvement, with the ultimate goal of reducing the probability and reliability impact of future system events.
- **Fostering Collaboration:** Increased efficient and effective collaboration amongst NERC and the Regional Entities has resulted through the centralization and appropriately secure distribution of information across Regions (including EA results, trending analysis, and lessons learned), and the increased clarity and standardization of processes provided by the software solution.

RADS. The RADS system provides for a more efficient method for NERC to complete seasonal and long-term reliability assessment reports. Specifically, RADS automates the importing of data, provides for ad hoc and pre-defined reporting, and provides access to historical data. In fact, a recent benchmarking exercise indicated that RADS enabled a routine data import process to be completed in 22 minutes as compared to prior manual work efforts totaling roughly 80 hours. This process improvement has allowed NERC's analysts and engineers to spend more time analyzing reliability and less time importing and managing data. Additional benefits of RADS include:

- **Management of Reliability Risk.** By allowing analysts to refocus their efforts on higher value work, the implementation of RADS is resulting in more and better analyses of future conditions and risks.
- **Improved Quality.** Part of the reason for the respected status of the ERO and its assessments is the high level of quality embodied within its documents. If factual errors were introduced into NERC's reliability assessments, such errors would considerably diminish the ERO's credibility. By centralizing information and reducing the number of manual interventions required to manage data, the RADS system aids in ensuring that the information contained within NERC assessments is accurate and correct.
- **Increased Security.** NERC has obligations to ensure the integrity and security of assessment data. Having a central place to manage and store assessment data has reduced the number of instances of confidential proprietary data being handled and managed at NERC. As such, the risk of accidental inappropriate disclosure has been reduced.

Document Management. As a third example, as described previously, NERC commenced implementation of a document management program during 2015 and 2016. The evaluation of the cost-benefit of the document management program indicated tremendous value to the organization, primarily in terms of addressing the business requirements set forth above. The cost benefit analysis of this project also demonstrated that NERC's projected average cost per user is comparable to market. In addition, assuming achievement of modest personnel efficiency gains (between 2-7 percent) from using the new system, the program will generate value in terms of increased resource availability well above anticipated costs. The project was reviewed in depth with the board of trustee's Standards Oversight and Technology Committee and Finance and Audit Committee, which, together with the Board, authorized reserve funding at their May, 2015 meetings to commence initiation of the program.

In all three of these examples, NERC's planning process and associated approval gates have led to thorough review of both costs and benefits of technology benefits prior to moving forward. As the planning process has matured, NERC has begun to analyze potential benefits to the Regional Entities when considering the benefits from potential IT investments. In the Enterprise Reporting – GADS business case brought before the TLT in April, NERC included estimates of productivity gain in terms of both NERC staff and the staff of the Regional Entities. NERC estimated that across the ERO Enterprise, in the first year of operation, 32 Regional Entity employees would save roughly 10 hours of time and 42 NERC employees would save roughly 29 hours of time, with benefits increasing in future years as users became more familiar with the system and as the system was expanded with additional data. This saved time represents additional value that those employees can provide by not having to manage data or duplicate work. Beyond this analysis, the business case considered less quantifiable benefits to both NERC and the Regional Entities in terms of supporting the ERO Enterprise Strategic Plan and reducing reliability risk.

As the planning process continues to develop and mature, NERC will continue to expand incorporation of regional staffing and budget impacts into its business case analysis, as well as identifying economies of scale, efficiency improvements, and enhancements to reliability through IT investment.

Resource Requirements

Personnel

The increase in Information Technology FTEs is due to the reallocation of personnel to strengthen project management oversight over NERC and ERO Enterprise software application development and implementation.

Contract and Consulting Resources to Support Internal Operations

The 2017 budgeted amounts are set forth in Exhibit C, with a comparison to 2016 budgeted amounts. The increase in the 2017 budget compared to 2016 is primarily due to the inclusion of ongoing maintenance costs for recently added ERO Enterprise applications and costs for the document management program.

2017 IT Operating Expenses

A summary of the major categories of IT Operating Expenses are set forth in the following table:

Office Costs	Budget 2016	Budget 2017	Variance
Telephone	$ 225,000	$ 230,000	$ 5,000
Telephone - Answering Service	3,000	2,500	(500)
Internet	350,000	358,920	8,920
Computer Supplies and Maintenance			
Computers	25,000	25,000	-
Computer Supplies	96,100	98,100	2,000
Maintenance & Service Agreements	1,365,295	1,706,088	340,793
Software	59,000	59,000	-
Subscription and Publications	108,300	108,300	
Dues	2,500	2,500	
Express Shipping	5,000	5,000	-
Total Office Costs	**$ 2,143,420**	**$ 2,595,408**	**$ 356,213**

Telephone Expenses
Office telephone costs are items associated with cellular phone, mobile laptop cellular air card, Session Internet Protocol (SIP) data circuits, and conference calling expenses.

Internet Expense
Internet expense is comprised of data circuits, and redundant capability in the event of primary service provider failure.

Computer Supplies and Maintenance
Computers are items that do not meet the criteria to be considered a capital expense, such as desktop computers or iPads. Computer supplies are expense items required for infrastructure support. Maintenance and service agreements comprise those items required to support internal and external access to routers, switches, firewalls, intrusion protection, file servers, audiovisual equipment, storage area networks, data backup services, network and security monitoring, co-location data center services, video conferencing, digital certificates, and development and virtualization software. Service agreements related to the co-location data center, offsite backup of data, conference calling, and network and security monitoring consume a large portion of the maintenance and service agreements budget.

Software
Tools such as Adobe Creativity Suite, remote support tools, and various other IT support tools are included under this line item. The tools are primarily used for NERC infrastructure purposes to support and manage the application, server, and network environment.

2017 IT Fixed Asset (Capital) Expenses
The following table presents a summary of NERC's IT 2017 fixed asset (capital) budget[37] compared to the 2016 budget:

IT CAPITAL BUDGET	2016	2017
ERO Application Development	$ 1,500,000	$ 700,000
Document Management	465,000	335,000
Hardware (Storage, servers, laptops)	955,000	991,000
Other Equipment	535,000	885,000
Disaster Recovery	200,000	150,000
NERC Software licenses	256,000	211,000
Total IT Capital Budget	**$ 3,911,000**	**$ 3,272,000**

As in prior years, the goal of the 2017–2019 planning period is to provide access, visibility, and analysis of data from many different sources; this will requires ongoing investments in hardware, software, and associated tools. The overarching theme is to securely gather, analyze, and maintain data across the ERO Enterprise to support ERO operations. Adding the capability to centralize and mine data—in addition to foundational elements such as the Microsoft xRM application, SharePoint 2013, and disaster recovery and enhanced security—sets the stage for vastly improved reporting and business intelligence. It also allows the capability for collaboration and sharing of information vital to the ERO's mission.

[37] NERC's total 2017 fixed asset (capital) budget is $4,372,000, and includes $1.1M budgeted in E-ISAC for portal enhancements and other costs related to CRISP.

In addition to the investments described above to support efficiency and consistency across the Enterprise, the 2017 budget also includes the cost of security enhancements, network assets, software, servers, laptops, and other hardware to support daily operations.

Human Resources

Background and Scope

Human Resources (HR) manages all of NERC's HR functions, including staffing, benefits administration, employee relations, performance and compensation management, and training and development. Management has implemented a robust, objective, and auditable performance management system to track corporate and individual performance against pre-established goals, objectives, and measures. Each year NERC continues to refine and improve this system.

Leadership, Management, and Professional and Administrative Staff Training and Development

As part of the 3-year ERO Enterprise Strategic Plan to engage and retain highly qualified talent with the leadership and technical skills to support the mission, NERC's executives, managers, and professional and support staff participate in ongoing training and development to improve competencies critical to success and succession planning for critical roles. As such, NERC will continue to invest in learning opportunities in several areas. First, HR will continue to host and optimize an e-leaning platform, SkillSoft, to provide staff resources for improving soft and technical skills. Second, HR will provide broad-based staff development training though real-world access via tours of and training on control centers, electric substations, and power generation plants. Finally, staff will have access to additional education, including but not limited to degree-oriented university education, pursuit of specialized certifications, and other in-house and external training that provides essential competencies and skills development that will lead to improved organization performance.

Compensation Consulting

Consultants are periodically retained to examine appropriate compensation based on current market data. This ensures that decisions affecting compensation are made in light of the current market climate and that qualified employees are attracted and retained within a defined total remuneration range. NERC also periodically retains compensation subject matter experts to perform periodic assessments of the BOT compensation model to ensure alignment with market practices.

Surveys

NERC periodically retains a vendor to conduct Board of Trustees and committee effectiveness surveys to identify improvement opportunities. HR will also launch additional surveys as appropriate, based on business needs, which may include periodic internal climate surveys.

Succession Planning

Minimizing disruption of knowledge, skill, and experience of key staff is critical to the company's success. HR works with senior management to identify essential roles and develop strategies to build succession and contingency plans for any loss of staff.

HR Products and Services Automation

HR will continue to operate, maintain, and investigate investment in additional electronic platforms for HR support services that reduce administrative burden and improve employee access to tools and information.

Resource Requirements

Personnel
The slight increase in FTEs is due a lower vacancy rate in 2017 compared to 2016.

Contractor Expenses
Contractor and consultant expenses are set forth in additional detail in Exhibit C. The increase over 2016 is primarily due to increased investments for additional leadership and staff training.

Miscellaneous Expenses
Miscellaneous expenses include community responsibility and employee engagement, the year-end employee appreciation event, and employee rewards and recognition.

Finance and Accounting

Background and Scope

NERC's Finance and Accounting department manages all finance and accounting functions, including employee payroll, 401(k), 457(b), and 457(f) plans, travel and expense reporting, monthly financial reporting, sales and use tax, meeting and events planning and services, insurance, internal auditing, and facilities management. This area also holds primary responsibility for the development of the annual business plan and budget, as well as NERC's proposed ERO risk management framework. Over the past several years, NERC's Finance and Accounting department implemented additional policies, procedures, and controls governing day-to-day practices including contract and personnel procurements, meetings, conference planning and travel, expense reimbursement, and back office systems and procedures. The department will continue to refine, improve and, where necessary, implement additional procedures and controls.

Resource Requirements

Personnel
The reduction in FTEs is due to a reallocation of resources to other departments in 2016.

Contractor Expenses
$457k is budgeted for outside contractor and consulting support, representing an increase compared to the 2016 budget. These costs are primarily for outside professional support for auditors to support various risk management and internal control and audit intiatives, as well as to provide finance and accounting support.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
ADMINISTRATIVE SERVICES

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 561,427	$ 626,997	$ 65,570	$ 519,083	$ (42,344)	$ 952,667	$ (433,583)
Penalty Sanctions	-	-	-	-	-	-	-
Total NERC Funding	**$ 561,427**	**$ 626,997**	**$ 65,570**	**$ 519,083**	**$ (42,344)**	**$ 952,667**	**$ (433,583)**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	-	-	-	-	-	-	-
Interest	-	-	-	-	-	-	-
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 561,427**	**$ 626,997**	**$ 65,570**	**$ 519,083**	**$ (42,344)**	**$ 952,667**	**$ (433,583)**
Expenses							
Personnel Expenses							
Salaries	$ 11,054,511	$ 11,050,223	$ (4,288)	$ 11,858,590	$ 804,078	$ 11,864,014	(5,425)
Payroll Taxes	662,269	656,558	(5,711)	669,299	7,030	687,162	(17,862)
Benefits	1,369,805	1,348,538	(21,267)	1,333,443	(36,362)	1,385,477	(52,034)
Retirement Costs	1,024,669	1,101,571	76,902	1,073,642	48,973	1,088,601	(14,959)
Total Personnel Expenses	**$ 14,111,254**	**$ 14,156,890**	**$ 45,636**	**$ 14,934,974**	**$ 823,720**	**$ 15,025,254**	**(90,280)**
Meeting Expenses							
Meetings	$ 315,000	$ 351,681	$ 36,681	$ 350,000	$ 35,000	$ 315,000	35,000
Travel	653,945	651,240	(2,705)	653,945	-	653,945	-
Conference Calls	63,300	62,110	(1,190)	19,307	(43,994)	19,307	-
Total Meeting Expenses	**$ 1,032,245**	**$ 1,065,031**	**$ 32,786**	**$ 1,023,251**	**$ (8,994)**	**$ 988,251**	**35,000**
Operating Expenses							
Consultants & Contracts	$ 3,036,671	$ 2,585,495	$ (451,176)	$ 3,359,787	$ 323,116	$ 3,199,787	160,000
Office Rent	3,054,287	2,987,777	(66,510)	3,117,009	62,722	3,117,009	-
Office Costs	2,920,678	2,713,155	(207,523)	3,275,952	355,274	3,245,952	30,000
Professional Services	2,334,300	1,961,280	(373,020)	2,293,135	(41,165)	2,293,135	-
Miscellaneous	32,000	32,000	-	32,000	-	32,000	-
Depreciation	1,920,234	1,751,253	(168,981)	1,233,650	(686,584)	1,233,650	-
Total Operating Expenses	**$ 13,298,171**	**$ 12,030,960**	**$ (1,267,210)**	**$ 13,311,534**	**$ 13,363**	**$ 13,121,534**	**$ 190,000**
Total Direct Expenses	**$ 28,441,669**	**$ 27,252,881**	**$ (1,188,788)**	**$ 29,269,759**	**$ 828,090**	**$ 29,135,039**	**$ 134,720**
Indirect Expenses	**$ (28,551,669)**	**$ (27,323,087)**	**$ 1,228,582**	**$ (29,376,484)**	**$ (824,815)**	**$ (29,257,139)**	**$ (119,345)**
Other Non-Operating Expenses	**$ 110,000**	**$ 70,206**	**$ (39,794)**	**$ 106,725**	**$ (3,275)**	**$ 122,100**	**(15,375)**
Total Expenses (B)	**$ -**	**$ 0**	**$ (0)**	**$ -**	**$ 0**	**$ -**	**$ 0**
Change in Assets	**$ 561,427**	**$ 626,997**	**$ 65,570**	**$ 519,083**	**$ (42,344)**	**$ 952,667**	**(433,583)**
Fixed Assets							
Depreciation	(1,920,234)	(1,751,253)	168,981	(1,233,650)	686,584	(1,233,650)	-
Computer & Software CapEx	2,347,000	2,749,562	402,562	1,472,000	(875,000)	1,572,000	(100,000)
Furniture & Fixtures CapEx	-	14,611	14,611	-	-	-	-
Equipment CapEx	1,464,000	365,000	(1,099,000)	1,800,000	336,000	1,800,000	-
Leasehold Improvements	-	566,361	566,361	-	-	-	-
Allocation of Fixed Assets	(1,890,766)	(1,944,281)	(53,515)	(2,038,350)	(147,584)	$ (2,138,350)	100,000
Inc(Dec) in Fixed Assets (C)	**$ -**	**$ -**	**$ (0)**	**$ -**	**$ (0)**	**$ -**	**$ 100,000**
TOTAL BUDGET (=B + C)	**$ -**	**$ 0**	**$ (0)**	**$ -**	**$ 0**	**$ -**	
FTEs	**71.23**	**73.62**	**2.39**	**69.33**	**(1.91)**	**71.36**	**(2.03)**

Section B — Supplemental Financial Information

Breakdown by Statement of Activity Sections

The following detailed schedules support the consolidated Statement of Activities. All significant variances were described by program area in the preceding pages.

Table B-1
Operating Reserve and Assessment Analysis

Operating Reserve and Assessment Analysis Statutory		Total Reserves	Future Obligations Reserve[1]	Operating Contingency Reserve	Operator Certification	CRISP	Assessment Stabilization Reserve
Beginning Working Capital and Operating Reserves Balance		**6,075,782**	**3,431,795**	**1,213,419**	**930,568**	**500,000**	
Generation or (Use) from 2016 Operations							
From 2016 budgeted operations		862,799		1,109,651	(246,852)		
From 2016 approved use of reserves		(1,117,056)	(320,218)	(796,838)			
Proceeds from financing activities (non-current portion only)		1,256,042		1,256,042			
Debt Service		(1,055,000)		(1,055,000)			
Other adjustments to reserves		1,806,132	(464,868)	-			2,271,000
Projected Working Capital and Operating Reserves - 12/31/16		**7,828,700**	**2,646,709**	**1,727,275**	**683,716**	**500,000**	**2,271,000**
Required Working Capital and Operating Reserves - 12/31/17	[2]	**7,759,102**	2,646,709	2,227,275	714,118	500,000	1,671,000
Adjustment in funding to achieve required reserve balance		530,402	-	500,000	30,402	-	
Penalty sanctions available 1-1-2017 (See Table B-2)		500,000					500,000
Less: Penalty sanction offset in 2017		(1,100,000)		-			(1,100,000)
Total Adjustments to Reserves		**(69,598)**	**-**	**500,000**	**30,402**	**-**	**(600,000)**
Assessment Reconciliation							
2017 Expenses and Capital Expenditures		69,602,175		60,018,178	1,291,557	8,292,440	
Less: Penalty sanction offset in 2017		(1,100,000)		(1,073,757)		(26,243)	
Adjustment in funding to achieve required reserve balance		530,402	-	500,000	30,402	-	
Less: Other Funding Sources		(9,195,417)	-	(882,942)	(1,321,958)	(6,990,517)	
Less: Proceeds from financing activities (non-current only)		(966,667)		(966,667)			
Plus: debt service		985,750		985,750			
2017 NERC Assessment		**59,856,243**					

[1] As further explained in the discussion of the Working Capital Reserve amount in Exhibit E, the Future Obligations Reserve offsets future, non-current liabilities. The calculation of Working Capital and Operating Reserve balances per 2015 audited financials and as projected for 2016 and 2017 is included with the Statements of Financial Position on page 91.

[2] On August 11, 2016, the NERC Board of Trustees approved the Working Capital and Operating Reserve Balance at 12/31/17.

Table B-2
Penalties

Penalty Sanctions

Until recently, penalty monies received prior to June 30 were to be used to offset assessments in the subsequent year's budget, as documented in *NERC Policy – Accounting, Financial Statement and Budgetary Treatment of Penalties Imposed and Received for Violations of Reliability Standard*, as well as Section 1107.2 of the Rules of Procedure. The NERC Board has approved an updated Working Capital and Operating Reserves Policy that has also been approved by FERC. This updated Policy allows NERC, with FERC approval pursuant to Section 1107.4 of the Rules of Procedure, to place penalty funds into a new Assessment Stabilization Reserve for use in future years to offset assessments. For the 2017 budget, $500,000 of penalty funds received prior to June 30, 2016 were deposited into this reserve account. NERC proposes that $1,100,000 of those funds be used to offset assessments for the 2017 budget with the remaining $1,671,000 held in the Assessment Stabilization Reserve for future assessment offsets.

All penalties received through June 30, 2016 are detailed below, including the amount and date received.

Allocation Method

Penalty sanctions used to offset 2017 assessments have been allocated to the following statutory programs to reduce assessments: Reliability Standards, Compliance Assurance, Compliance Analysis and Certification, Compliance Enforcement, Reliability Assessments and System Analysis, Performance Analysis, Training and Education, Situation Awareness, Event Analysis, and E-ISAC. Penalty sanctions are allocated based on the number of FTEs in the program divided by the aggregate total FTEs in the programs receiving the allocation. In addition to the information noted below, an additional $500,000 is expected in May 2017 related to an agreed-upon penalty settlement through WECC resulting from the September 2011 blackout.

Penalty Sanctions	Date Received	Amount Received
Penalties received between 7/1/2015 and 6/30/2016		
	May-16	$ 500,000
		$ 500,000
Penalties received prior to 6/30/2015, held in the assessment stabilization reserve		$ 2,271,000
Total penalties available to offset assessments		$ 2,771,000
Adjustments		
Penalties held in assessment stabilization reserve		(1,671,000)
Total Penalty Sanctions included in the 2017 Budget		$ 1,100,000

Table B-3
Outside Funding

Outside Funding Breakdown By Program (Excludes Penalty Sanction)	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget
Reliability Standards				
Workshops	$ 105,000	$ 105,000	$ 105,000	$ -
Interest Income Allocation	445	5,374	427	(18)
Total	$ 105,445	$ 110,374	$ 105,427	$ (18)
Compliance Analysis, Registration and Certification				
Interest Income Allocation	$ 251	$ 2,860	$ 187	$ (64)
Total	$ 251	$ 2,860	$ 187	$ (64)
Compliance Assurance				
Workshops	$ -	$ -	$ -	$ -
Interest Income Allocation	479	$ 4,710	386	(93)
Total	$ 479	$ 4,710	$ 386	$ (93)
Compliance Enforcement				
Interest Income Allocation	$ 302	$ 3,682	$ 327	$ 25
Total	$ 302	$ 3,682	$ 327	$ 25
Reliability Assessments and System Analysis				
pc_GAR Software	$ 50,000	$ -	$ 50,000	$ -
Workshops	15,000	15,000	15,000	-
Interest Income Allocation	462	3,634	351	(111)
Total	$ 65,462	$ 18,634	$ 65,351	$ (111)
Performance Analysis				
Interest Income Allocation	$ -	$ 2,554	$ 234	$ 234
Total	$ -	$ 2,554	$ 234	$ 234
Training and Education				
Testing Fees and Certificate Renewals	$ 1,267,972	$ 1,267,972	$ 1,321,900	$ 53,928
CEH Fees	600,000	600,000	600,000	-
Interest Income Allocation	183	2,096	175	(7)
Total	$ 1,868,155	$ 1,870,068	$ 1,922,075	$ 53,921
Event Analysis				
Workshops	$ 40,000	$ 78,073	$ 40,000	$ -
Interest Income Allocation	274	2,918	281	7
Total	$ 40,274	$ 80,991	$ 40,281	$ 7
Situation Awareness				
Workshops	$ -	$ 1,128	$ -	$ -
Interest Income Allocation	137	1,816	140	3
Total	$ 137	$ 2,944	$ 140	$ 3
E-ISAC				
Third Party Funding (CRISP)	$ 6,830,738	$ 7,335,757	$ 6,990,447	$ 159,709
Workshops	70,000	70,000	70,000	-
Interest Income Allocation	468	6,254	491	24
Total	$ 6,901,206	$ 7,412,011	$ 7,060,938	$ 159,732

- Operator Certification – The 2017 budget reflects prior year actual results and the anticipated number of tests to be taken in 2017.
- E-ISAC – The increase in third-party funding is due to the increase in NERC costs, which are funded equally by participants in CRISP and through assessments.

Table B-4
Personnel

Personnel Expenses	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Total Salaries	$ 28,842,336	$ 29,052,918	$ 30,073,438	$ 1,231,102	4.3%
Total Payroll Taxes	1,871,367	1,830,724	1,847,130	(24,237)	-1.3%
Total Benefits	3,579,280	3,390,190	3,643,806	64,526	1.8%
Total Retirement	2,990,823	3,015,135	3,076,956	86,134	2.9%
Total Personnel Costs	$ 37,283,807	$ 37,288,967	$ 38,641,331	$ 1,357,525	3.6%
FTEs	192.47	145.02	189.88	(2.59)	-1.3%
Cost per FTE					
Salaries	$ 149,852	$ 200,337	$ 158,381	8,529	5.7%
Payroll Taxes	9,723	12,624	9,728	5	0.1%
Benefits	18,596	23,377	19,190	594	3.2%
Retirement	15,539	20,791	16,205	666	4.3%
Total Cost per FTE	**$ 193,710**	**$ 257,130**	**$ 203,504**	**$ 9,794**	**5.1%**

- Salaries - Total Salaries expense is comprised of base salaries, incentive compensation, deferred compensation, employment agency fees and temporary office expenses. The 2017 budget for base salaries assumes a 3% increase over actual 2016 base salaries and is inclusive of market adjustments and promotions. Due to the addition of more senior staff in 2016, and the need to pay higher market-based compensation than previously budgeted to attract and retain employees, the actual average salary is higher than the 2016 budget, which causes the comparison of 2017 budget to 2016 budget to be higher than 3%. The 2017 budget for incentive compensation is based on historical actuals and is slightly higher as a percent of base salaries, 20.9% in 2017 compared to 19.5% in 2016. The 2017 budgets for deferred compensation, employment agency fees and temporary office expenses are generally consistent with 2016.
- Payroll taxes are decreasing based upon the 2016 projection and the reduction in total FTEs. While total Salaries expense is increasing, the maximum salary subject to FICA taxes limits the change in employer costs.
- Benefits are budgeted to increase based on the most recent market data as provided by NERC's insurance broker.
- There have been no changes to NERC's retirement plans. Retirement expenses are increasing at a higher rate consistent with the 3% increase in base salaries.

Table B-5
Meetings

Meetings	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Meetings	$ 1,096,500	$ 1,194,500	$ 1,071,500	$ (25,000)	-2.28%
Travel	$ 2,203,786	$ 2,190,184	$ 2,203,786	(0)	0.62%
Conference Calls	$ 320,000	$ 261,880	$ 97,600	(222,400)	-62.73%
Total Meetings	**$ 3,620,286**	**$ 3,646,564**	**$ 3,372,886**	**$ (247,400)**	**-6.83%**

- The 2017 budget for Meetings expense in the Operator Certification Program is $25.0k lower than the 2016 budget based upon prior year actual results.
- The 2017 budget for Conference Calls is $222.4k, 69.5%, lower than 2016 based upon the planned execution of a contract with a new provider scheduled to occur in 2016. This reduction in Conference Calls expenses will offset an increase in maintenance costs associated with a new audio visual lease related to new equipment and associated service and maintenance agreements.

Table B-6
Consultants and Contracts

NOTE: This table has been replaced by Exhibit C, and is further discussed in the Executive Summary on page 14

Table B-7
Rent

Office Rent	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Office Rent	$ 2,987,777	$ 2,954,287	$ 2,838,144	$ (149,633)	-5.01%
Utilities	-		-	-	
Maintenance	100,000	270,000	278,866	178,866	3.28%
Total Office Rent	**$ 3,087,777**	**$ 3,224,287**	**$ 3,117,009**	**$ 29,232**	**0.95%**

- The decrease in Office Rent is due to the termination of the lease at NERC's former Washington, DC office.
- Maintenance costs at NERC offices increase year over year per the terms of the lease agreements.

Table B-8
Office Costs

Office Costs	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Telephone	$ 548,596	$ 410,053	$ 539,737	$ (8,859)	-1.61%
Telephone Answering Srv	3,000	3,355	2,500	(500)	-16.67%
Internet	375,900	369,021	383,366	7,466	1.99%
Office Supplies	173,800	177,392	194,000	20,200	11.62%
Computer Supplies and Maintenance	-	-	-	-	
Computers	25,000	26,000	25,000	-	0.00%
Computer Supplies	98,400	85,607	101,400	3,000	3.05%
Maintenance & Service Agreements	1,875,126	1,858,992	2,426,139	551,013	29.39%
Software	117,500	226,643	122,500	5,000	4.26%
Network Supplies	-	-	-	-	
Publications & Subscriptions	167,650	190,852	180,460	12,810	7.64%
Dues	48,050	63,165	49,316	1,266	2.64%
Postage	16,350	15,786	16,221	(129)	-0.79%
Express Shipping	28,200	17,405	28,216	16	0.06%
Copying	105,000	104,993	110,123	5,123	4.88%
Reports	2,000	1,362	362	(1,638)	-81.90%
Stationary/Forms	2,500	1,090	2,500	-	0.00%
Equipment Repair/Service Contracts	75,000	75,000	75,000	-	0.00%
Bank Charges	42,500	26,494	25,000	(17,500)	-41.18%
Sales & Use Taxes	5,000	500	-	(5,000)	-100.00%
Merchant Card Fees	86,000	86,575	77,500	(8,500)	-9.88%
Total Office Costs	**$ 3,583,328**	**$ 3,740,288**	**$ 4,359,340**	**$ 563,768**	**21.66%**

- The increase in Office Supplies is primarily related to increased needs at NERC's Washington, D.C. office.
- The increase in Maintenance and Service agreement costs related to:
  - New in software audit tool in Compliance Assurance, $100k
  - New software analytic tools used in RASA, $37k
  - Increase in maintenance costs for new data center hardware installed in 2015 and 2016, and new network storage devices, $200k
  - Increase in maintenance costs for new audio visual equipment planned for 2016, $164k

Table B-9
Professional Services

Professional Services	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Independent Trustee Fees	$ 1,126,354	$ 1,126,354	$ 1,226,000	$ 99,646	8.85%
Trustee Search Fee	100,000	100,000	100,000	-	0.00%
Outside Legal	690,000	590,000	515,000	(175,000)	-25.36%
Lobbying	50,000	50,000	60,000	10,000	20.00%
Accounting & Auditing Fees	154,500	154,500	159,135	4,635	3.00%
Insurance Commercial	225,000	225,000	230,000	5,000	2.22%
Outside Services	163,446	168,446	178,000	14,554	8.90%
Total Services	**$ 2,509,300**	**$ 2,414,300**	**$ 2,468,135**	**$ (41,165)**	**-1.64%**

- The increase in Independent Trustee Fees was approved by the Board of Trustees on August 13, 2015. Independent Trustee Fees are included in the Professional Services budget in the General and Administrative and Executive department.
- The reduction in outside legal fees, budgeted in the Legal and Regulatory department, is based on bringing more work in-house and a reduction in projected outside legal needs due to the completion of certain contract negotiations.
- The increase in Lobbying expense, budgeted in the Legal and Regulatory department, is based upon prior year actual expenses. This expense is primarily related to NERC's monitoring of regulatory and legislative issues and responding to information requests related to these activities.
- The increase in outside service costs is primarily due to various employee benefit management systems budgeted in the Human Resources department.

Table B-10
Miscellaneous

Miscellaneous Expenses	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Miscellaneous Expense	$ 6,500	$ 6,500	$ 6,500	$ -	0.0%
Employee Rewards and Recognition	10,000	$ 10,000	10,000	-	0.0%
Community Resp & Employee Engagement	10,000	10,000	5,000	(5,000)	-50.0%
Year-end Employee Recognition Event	10,000	10,000	15,500	5,500	55.0%
Total Miscellaneous Expenses	**$ 36,500**	**$ 36,500**	**$ 37,000**	**$ 500**	**1.4%**

The total 2017 Miscellaneous Expenses budget shows a minor increase of $500 over the 2016 budget.

This budget is intended to cover the cost of:

1. Token gifts to retiring employees, condolence flowers in the event of a death in the family of an employee, and similar types of miscellaneous expenses ($6.5k);
2. Funds to support Community Responsibility and Employee Engagement Committee activities ($5.0k);
3. Departmental and company team-building activities and employee rewards and recognition expenses that are not otherwise included in personnel expenses ($10.0k); and
4. Year-end employee recognition meal expenses ($15.50k). $5.0k was reallocated from Community Responsibility and Employee Engagement expenses to the Year-End Employee Recognition Event to better align the budget with prior year actual results.

The budget for item (1) is spread throughout all Programs and Administrative departments. The budget for items (2) and (4) are included in the Human Resources department. The budget for item (3) was split equally between General and Administrative and Human Resources in the 2016 Budget, but is budgeted in Human Resources only in 2017.

Table B-11
Other Non-Operating Expenses

Other Non-Operating Expenses	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Property Tax Expense	$ 50,000	50,000	$ 50,000	-	
Interest Expense	60,000	60,000	56,725	(3,275)	-5.46%
Total Other Non-Operating Expenses	**$ 110,000**	**$ 110,000**	**$ 106,725**	**$ (3,275)**	**-2.98%**

Budgeted interest expense is calculated based on expected draws on the capital financing loan. Refer to Exhibit D, page 125 for more detailed information related to debt repayment and the interest expense calculation.

Table B-12
Fixed Assets

Fixed Assets	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Depreciation	$ (2,641,943)	$ (2,558,606)	$ (1,691,457)	$ 950,486	-35.98%
Computer & Software CapEx	2,447,000	2,362,402	2,572,000	125,000	5.11%
Furniture & Fixtures CapEx	-	-	-	-	
Equipment CapEx	1,464,000	1,545,797	1,800,000	336,000	22.95%
Leasehold Improvements	-	-	-	-	
	$ 1,269,057	**$ 1,349,593**	**$ 2,680,543**	**$ 1,411,486**	**111.22%**

As further explained in the Executive Summary on page 15 and in Section A in the Information Technology section on page 77 and the E-ISAC section on page 61, expenditures for fixed assets, excluding the reversal of Depreciation expense, are budgeted to be $461.0k higher in 2017 compared to 2017. The increase in Computer & Software CapEx is primarily due to the combination of lower costs resulting from a delay in the potential replacement for the current compliance monitoring and enforcement tracking tool, originally planned for 2017, and the increase in costs related to the portal enhancement project. This delay in the compliance monitoring and enforcement tracking tool resulted in a $800k decrease in ERO applications development from $1.5M in 2016 to $700k in 2017. The increase in Equipment CapEx is primarily for security devices.

Table B-13
2018-2019 Projections
NOTE: Refer to the Executive Summary beginning on page 21

Section C — Non-Statutory Activity

NERC has no non-statutory activities.

Section D — Supplemental Financial Statements

NORTH AMERICAN ELECTRIC RELIABILITY COPORATION

STATEMENT OF FINANCIAL POSITION

	12/31/2015 Per Audit	12/31/2016 - Projection	12/31/2017 - Projection
ASSETS			
Cash	40,308,955	39,464,020	39,091,525
Trade Accounts receivable, net of allowance for uncollectible accounts of $0 and $62,573 in 2013 and 2012	3,986,346	3,986,346	3,986,346
Prepaid expenses and other current assets	1,291,805	1,291,805	1,291,805
Security deposit	125,416	125,416	125,416
Plan Assets - 457b	744,439	744,439	744,439
Plan Assets - 457f	271,200	271,200	271,200
Property and equipment	8,301,730	9,411,545	12,669,171
Total Assets	**55,029,891**	**55,294,771**	**58,179,902**
LIABILITIES AND NET ASSETS			
Liabilities			
Current Portion			
Accounts payable and accrued expenses (incl, vacation accrual)	5,326,723	5,326,723	5,326,723
Accrued Incentive Comp	4,721,278	4,956,779	4,872,492
Deferred rent-current	322,016	400,434	480,457
Deferred compensation-current	-	-	-
Capital lease obligations - current	64,728	64,728	64,728
Accrued retirement liabilities	1,878,830	1,695,570	1,761,502
Debt Service - Current Portion	744,253	857,725	650,231
Deferred income	7,961,316	7,961,316	7,961,316
Deferred revenue - penalties	-	-	-
Deferred revenue - CRISP	2,508,514	2,508,514	2,508,514
Regional assessments	12,273,666	12,273,666	12,273,666
Total Current Portion	**35,801,324**	**36,045,455**	**35,899,629**
Long-Term Portion			
Deferred compensation[1]	1,038,350	1,038,350	1,038,350
Capital Project Financing - non-current	680,311	1,011,839	1,033,333
Deferred rent - non-current	3,412,298	3,011,864	2,531,407
CRISP Insurance Reserve	500,000	500,000	500,000
Deferred Revenue - Assessment Stabilization Reserve	-	2,271,000	2,271,000
Capital lease obligations - non-current	151,752	151,752	151,752
Total Non-Current Portion	**5,782,711**	**7,984,805**	**7,525,842**
Total Liabilities	**41,584,035**	**44,030,260**	**43,425,472**
Net Assets - unrestricted	9,735,856	10,764,511	14,254,430
Net Assets - restricted	3,710,000	500,000	500,000
Total Liabilities and Net Assets	**55,029,891**	**55,294,771**	**58,179,902**

[1]Includes 457b liability, life insurance for former executive, and retiree medical

NORTH AMERICAN ELECTRIC RELIABILITY COPRORATION

Statement of Activities, Fixed Asset Expenditures and Change in Working Capital by Program	Statutory Total	Statutory Activities: Reliability Standards	Compliance Analysis, Registration & Certification	Compliance Assurance	Compliance Enforcement	Reliability Assessment and System Analysis	Performance Analysis	Operator Certification	Training and Continuing Education	Event Analysis	Situation Awareness	E-ISAC	General and Administrative (Includes Executive and Gov't Relations)	Legal and Regulatory	Information Technology	Human Resources	Accounting and Finance
Funding																	
ERO Funding																	
NERC Assessments	59,856,314	7,835,213	3,576,122	7,713,879	5,677,854	7,339,030	4,821,146		1,822,089	5,300,955	3,980,236	11,270,705	519,083	-	-	-	-
Penalty Sanctions	1,100,000	159,642	69,980	144,334	122,465	131,213	87,475		43,738	104,970	52,485	183,698			-		
Total NERC Funding	**60,956,314**	**7,994,855**	**3,646,102**	**7,858,213**	**5,800,319**	**7,470,243**	**4,908,621**		**1,865,827**	**5,405,926**	**4,032,721**	**11,454,403**	**519,083**	-	-	-	-
Third-Party Funding (CRISP)	6,990,447											6,990,447					
Testing Fees	1,921,900							1,321,900	600,000								
Services & Software	50,000					50,000											
Workshops	230,000	105,000				15,000				40,000		70,000					
Interest	3,000	427	187	386	327	351	234	58	117	281	140	491					
Miscellaneous	-																
Total Funding (A)	**70,151,660**	**8,100,282**	**3,646,289**	**7,858,599**	**5,800,647**	**7,535,594**	**4,908,855**	**1,321,958**	**2,465,944**	**5,446,206**	**4,032,862**	**18,515,341**	**519,083**	-	-	-	-
Expenses																	
Personnel Expenses																	
Salaries	30,073,438	2,340,405	1,125,154	2,509,618	1,790,859	2,247,826	1,349,579	245,337	606,753	1,708,049	873,869	3,417,398	3,476,241	2,148,056	3,261,320	770,439	2,202,533
Payroll Taxes	1,847,130	151,658	76,383	163,335	117,205	142,919	92,093	18,342	44,385	108,739	58,749	204,023	173,245	119,055	216,747	28,144	132,107
Benefits	3,643,806	307,085	174,014	333,557	184,106	263,230	143,104	84,920	54,319	212,232	156,328	397,467	396,300	151,930	389,091	72,977	323,144
Retirement Costs	3,076,956	259,407	126,651	276,273	198,694	246,609	149,018	30,026	67,599	189,397	96,159	363,482	197,650	232,244	359,376	46,242	238,131
Total Personnel Expenses	38,641,331	3,058,556	1,502,203	3,282,783	2,290,865	2,900,585	1,733,794	378,625	773,056	2,218,416	1,185,105	4,382,370	4,243,437	2,651,285	4,226,534	917,802	2,895,916
Meeting Expenses																	
Meetings	1,071,500	207,000	4,000	60,000	2,500	74,000	1,000	30,000	25,000	81,500	6,500	230,000	334,000	4,000	7,500	2,000	2,500
Travel	2,203,786	271,988	155,146	276,343	56,736	208,338	118,172	7,389	13,751	152,487	33,005	256,488	444,515	93,231	56,508	8,728	50,963
Conference Calls	97,600	40,565	610	6,100	366	5,270	2,965	153	10,980	4,270	305	6,710	5,856	1,952	9,608	305	1,586
Total Meeting Expenses	3,372,886	519,553	159,756	342,443	59,602	287,608	122,137	37,541	49,731	238,257	39,810	493,198	784,371	99,183	73,616	11,033	55,049
Operating Expenses																	
Consultants & Contracts	13,127,749			50,000		525,000	528,082	219,800	360,800		1,295,850	6,788,429	15,000		2,312,787	575,000	457,000
Office Rent	3,117,009												3,117,009				
Office Costs	4,359,340	51,336	24,231	141,198	20,379	147,652	74,843	43,216	57,107	49,634	41,897	431,895	507,934	46,411	2,595,408	11,748	114,450
Professional Services	2,468,135											175,000	1,431,000	495,000		63,000	304,135
Miscellaneous	37,000	500	500	500	500	500	500		500	500	500	500	500	500	500	30,000	500
Depreciation	1,691,457	231,721				125,621			1,919	85,582	7,667	5,297	438,305		795,345		
Total Operating Expenses	24,800,690	283,556	24,731	191,698	20,879	798,773	603,426	263,016	420,326	135,715	1,345,914	7,401,121	5,509,749	541,911	5,704,041	679,748	876,085
Total Direct Expenses	**66,814,907**	**3,861,666**	**1,686,689**	**3,816,924**	**2,371,347**	**3,986,965**	**2,459,356**	**679,182**	**1,243,113**	**2,592,388**	**2,570,828**	**12,276,689**	**10,537,557**	**3,292,379**	**10,004,191**	**1,608,583**	**3,827,050**
Indirect Expenses	0	4,180,279	1,832,451	3,779,431	3,206,790	3,435,846	2,290,564	572,641	1,145,282	2,748,677	1,374,338	4,810,185	(10,644,282)	(3,292,379)	(10,004,191)	(1,608,583)	(3,827,050)
Other Non-Operating Expenses	**106,725**	-	-	-	-	-	-	-	-	-	-	-	106,725				
Total Expenses (B)	**66,921,632**	**8,041,945**	**3,519,141**	**7,596,355**	**5,578,137**	**7,422,812**	**4,749,920**	**1,251,823**	**2,388,395**	**5,341,065**	**3,945,167**	**17,086,873**	-	-	-	-	-
Change in Assets	**3,230,028**	**58,337**	**127,149**	**262,244**	**222,510**	**112,782**	**158,936**	**70,136**	**77,549**	**105,141**	**87,695**	**1,428,467**	**519,083**	-	-	-	-
Fixed Assets																	
Depreciation	(1,691,457)	(231,721)	-	-	-	(125,621)	-	-	(1,919)	(85,582)	(7,667)	(5,297)	(438,305)	-	(795,345)	-	-
Computer & Software CapEx	2,572,000											1,100,000			1,472,000		
Furniture & Fixtures CapEx	-																
Equipment CapEx	1,800,000														1,800,000		
Leasehold Improvements	-																
Allocation of Fixed Assets	0	290,058	127,149	262,244	222,510	238,403	158,936	39,734	79,468	190,723	95,361	333,765	438,305	-	(2,476,655)	-	-
Inc(Dec) in Fixed Assets (C)	**2,680,543**	**58,337**	**127,149**	**262,244**	**222,510**	**112,782**	**158,936**	**39,734**	**77,549**	**105,141**	**87,695**	**1,428,467**	-	-	-	-	-
TOTAL BUDGET (=B + C)	**69,602,175**	**8,100,282**	**3,646,289**	**7,858,599**	**5,800,647**	**7,535,594**	**4,908,855**	**1,291,557**	**2,465,944**	**5,446,206**	**4,032,862**	**18,515,341**	-	-	-	-	-
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**549,485**	**(0)**	-	-	-	**(0)**	**0**	**30,402**	-	-	**(0)**	**0**	**519,083**	-	-	-	-
FTEs	**189.88**	**17.16**	**7.52**	**15.51**	**13.16**	**14.10**	**9.40**	**2.35**	**4.70**	**11.28**	**5.64**	**19.74**	**16.92**	**11.28**	**23.27**	**2.82**	**15.04**

Exhibit A – Common Assumptions

Shared Business Plan and Budget Assumptions NERC and the Regional Entities 2016–2019 Planning Period (2017 Budget Cycle)

NERC and the eight Regional Entities are committed to a common operating model[38] that describes the characteristics of a highly effective and efficient electric reliability organization (ERO) Enterprise. This operating model includes action items to address coordinated strategic and business planning as well as performance monitoring processes across the enterprise. These processes remain transparent, with results reported out on a quarterly basis to NERC's Corporate Governance and Human Resources Committee and NERC Board of Trustees (Board) in support of the ERO corporate oversight function.

Recently, at its November 2015 meeting, the Board approved an updated version of the ERO Enterprise Strategic Plan with goals, objectives, and deliverables for the 2016–2019 planning period. The strategic plan lays out five goals that the ERO Enterprise will focus on over the next three years. They include (1) standards; (2) compliance, enforcement, registration, and certification; (3) risks to reliability; (4) emerging risks; and (5) coordination and collaboration. The plan also identifies a number of associated objectives and deliverables to achieve the goals of the ERO Enterprise. There are also four overarching performance metrics to assess the overall effectiveness of the ERO Enterprise in addressing risk to the Bulk Electric System (BES) and improving BES reliability in 2016. These metrics concentrate on (1) measuring progress in achieving reliability results, (2) assuring standards and compliance effectiveness, (3) improving risk mitigation, and (4) program execution.

The following set of common assumptions has been developed to guide ERO Enterprise resource projections[39] for the 2016–2019 period. Specifically, it supports the strategies heading into the 2016 year and establishes common assumptions, goals and objectives as the ERO Enterprise begins the 2017 Business Plan and Budget (BP&B) cycle. Additionally, it outlines how these goals and objectives set the stage for periods beyond 2017, all in support of achievement of the goals and objectives set forth in the Strategic Plan.

Similar to prior planning cycles, the specific resource needs and budgets of NERC and the Regional Entities will be publicly posted and made available on NERC's website for review. Each Regional Entity board approves its BP&Bs after an extensive review process that includes consideration of stakeholder input. Also, the BP&Bs of NERC and each Regional Entity are approved in open session by NERC's Finance and Audit Committee and Board of Trustees as part of the annual BP&B process. NERC's review of the Regional Entity BP&Bs will be primarily focused on ensuring alignment of activities with the Strategic Plan and adequacy of resources to support performance of delegated functions and key efforts. A 2017 BP&B schedule has been developed to identify important meeting dates, review periods, posting dates, etc. associated with the development and completion of the NERC and Regional Entity BP&Bs.

These assumptions will continue to be refined based on comments received from stakeholders and the ongoing work conducted by NERC and Regional Entity leadership regarding specific goals, objectives, and supporting activities over the planning period.

[38] ERO Enterprise Operating Model

[39] NERC recognizes there are often unique factors that drive differences in each entity or organization's final determination of its resource needs and budget. Regional Entity-specific assumptions are stated in each Regional Entity's BP&B as appropriate.

Legal and Operating Framework

NERC and the Regional Entities will continue to work under the existing regulatory framework governing the establishment and enforcement of reliability standards for the BES established by applicable governmental authorities in the United States, provincial regulatory and/or governmental authorities in Canada, and portions of Mexico, as well as the authorizations contained in the Federal Energy Regulatory Commission's (FERC) Order approving NERC as the ERO.

NERC continues to enhance its oversight of the Regional Entities' performance of their delegated functions. NERC in collaboration with the Regional Entities will continue to develop goals, measures, and reports to assess and evaluate the Regional Entities' performance of their Regional Delegation Agreements (RDAs), NERC's Rules of Procedure, the Compliance Monitoring and Enforcement Program, FERC requirements, and directives that are in effect pursuant to Section 8(c) of the RDAs. NERC will continue to provide feedback and direction to the Regional Entities on performance improvements. NERC and the Regional Entities will also continue to work collaboratively to refine and revise processes and procedures to eliminate duplication, increase operational efficiencies, enhance ERO-wide consistency, and achieve measureable reliability outcomes. Regional Entities will continue to have the primary responsibility for day-to-day operations and interactions with registered entities.

Stakeholder Participation

NERC and the Regional Entities develop their BP&B's based upon the assumption of continued stakeholder participation in support of key program areas, while recognizing that stakeholder resource limitations may affect specific levels of participation in any given activity. The availability and adequacy of industry resource support will be evaluated on an ongoing basis.

External Factors

The performance and execution of BP&B's for each entity in the ERO Enterprise may be impacted by various external factors. These factors include, but are not limited to, the following:

- FERC Orders, other applicable governmental authority actions, directives, audits, mitigation efforts, and performance assessments;
- Environmental Protection Agency (EPA) rules that could potentially impact the reliability and/or operation of the BES;
- Other governmental agencies or departments that may issue rules, guidelines, orders, or directives that may impact the operation of the BES;
- The number and significance of changes within Balancing Authorities' and Reliability Coordinators' areas, prompting the need for associated re-certification and reliability plan assessments;
- The unanticipated rise in the rate and severity of entity violations;
- The unanticipated rise in the rate and severity of system events requiring formal investigations beyond historic volumes, and causal drivers of these events;
- New technologies and changes in resource or demand composition that require additional reliability studies and reliability risk analysis, including new techniques for conducting relevant assessments;
- Changes in applicable laws and regulations, including environmental laws and others;
- Priority risk activities identified by the Reliability Issues Steering Committee, committees of the Board, and through other stakeholder input;

- The ability of stakeholders to support the pace and scope of the various activities while implementing the results of earlier efforts.

Collaboration with the Trade Associations and Forums

The activities of the North American Transmission Forum (NATF), North American Generator Forum (NAGF), and other trade forums and associations are expected to complement ERO Enterprise activities and mitigate incremental resource needs of NERC and Regional Entities in certain areas. NERC has a memorandum of understanding with the NATF and NAGF to help ensure that the common objectives of each organization are achieved in the most efficient and effective manner. Increased collaboration between the NERC and the NATF and NAGF is expected to continue.

Key Assumptions by Program Area[40]

Reliability Standards Program

- It is expected the number of continent-wide standards development projects will remain relatively stable, except as required to address any new FERC directives to create or modify reliability standards, or industry submittals of standard authorization requests.
- Continent-wide standards projects will consist primarily of conducting enhanced periodic reviews on existing standards to improve their content and quality, respond to identified risks to reliability (including those that may be identified through the implementation of risk-based Compliance Monitoring and Enforcement), and address FERC directives that may arise. This activity will require the allocation of technical resources from several internal NERC departments (e.g., Reliability Assessment and Performance Analysis (RAPA), Reliability Risk Management (RRM), Compliance Analysis and Certification, and Compliance Assurance) and support from across the ERO Enterprise.
- During the enhanced periodic review of ERO standards, any associated regional standards will be reviewed for potential incorporation as variances or as improvements to the continent-wide requirements. Regional and NERC standards development processes may require modification to accomplish efficiently this task. Each Regional Entity will work with NERC and possibly other Regional Entities on projects where there is a regional standard/variance. Regional standards development activity will be driven by requests the Regional Entity may receive or reliability issues the Regional Entity may identify. Regional standards development activity is expected to remain low.
- In coordination with Standard Drafting Teams and consistent with current approaches, Regional Entities may support outreach during standard development, and participate in the standard development activities as may be required to address reliability and stakeholder issues that may arise within their respective regions. Additionally, following FERC approval, NERC and the Regional Entities collectively will assist the transition of standards to compliance monitoring and enforcement by providing knowledge that supports industry and auditor training, or providing information regarding the intent of the standard.
- The number of interpretations are expected to remain low. However, guidance requests associated with the implementation of Standards may increase.

Compliance Monitoring and Enforcement, and Organization Registration and Certification Programs

[40] These statements, which are generally organized by program area, are intended to help guide resource allocation decision-making in the development of the 2017 BP&Bs.

Compliance and Enforcement

- The implementation of the risk-based compliance monitoring and enforcement program (CMEP) will continue to require the allocation of dedicated resources from both NERC and the Regional Entities for both compliance and enforcement. Regional Entities created a plan in 2016 to complete Inherent Risk Assessments (IRAs) for all their Reliability Coordinators, Balancing Authorities, and Transmission Operators and will require resources to complete the remaining IRAs in 2017. In addition, Regional Entities will require resources to update previously done IRAs based on identified triggers, and focus on creating compliance oversight plans that include compliance monitoring tools, the frequency of compliance monitoring, and the standards that are to be monitored as well as the depth of testing of those standards.
- NERC and the Regional Entities will continue the 2015-2016 ERO Enterprise exercises to evaluate business practices, implementation, and consistency within risk-based compliance monitoring.
- NERC and the Regional Entities will participate in ERO Enterprise consistency activities, including providing input into standards development.
- NERC and the Regional Entities are planning to support the training and education requirements and guidelines necessary to meet the criteria set forth by the *ERO Enterprise Compliance Monitoring and Enforcement Manual* and the *Competency Guide*.
- The suitability of software systems currently used for compliance, registration, analysis and tracking will continue to be evaluated from a strategic perspective, which may result in changing or replacing existing systems in the future. However, until such changes have been identified, reviewed and approved by the ERO Enterprise Technology Leadership Team and EROEMG for implementation, NERC and the Regional Entities should continue to maintain the necessary resources to support existing systems.
- Planning and operating standard violations are expected to level off or continue decreasing as most registered entities have been audited and thus have a greater understanding of compliance expectations, and the standards have matured.
- Compliance personnel will need to continue to support the implementation of cyber-security reliability standards version 5 (CIP V5):
    - NERC will lead the CIP V5 training development, coordination, and facilitation for the ERO Enterprise CIP auditors and industry outreach. ERO Enterprise CIP auditors will support these activities in collaboration with NERC to ensure appropriate knowledge and guidance is developed, understood by industry, and administered.
    - The allocation of resources in 2017 and 2018 should be responsive to continued implementation by registered entities of new versions of the CIP Standards, while recognizing that the risk-informed focus will be on monitoring “high” and “medium” impact requirements.
- Additional resource allocation may be necessary for increased Physical Security compliance monitoring activities for CIP-014.
- ERO Enterprise CMEP staff, particularly staff with visibility into risks occurring in the field, will provide feedback to the ERO Enterprise. This feedback may include information on risks seen in the field that are not addressed by a standard as well as information on where a standard is too broad. ERO Enterprise CMEP staff will participate in the development of a solution, regardless of whether the solution is a standard or other solution.

- ERO Enterprise CMEP staff will provide input for standards development teams on the risks seen in the field relating to a standard under development, as well as how a standard would be monitored.

Organization Registration and Certification

- Two central reforms have been identified as a result of the completion of the risk-based registration activity in 2015:

  1. Modifications to the NERC Registry Criteria have been approved, including the elimination of three functional entities (Purchasing-Selling Entities, Interchange Authorities, and Load-Serving Entities), modifications to the threshold criteria for Distribution Providers, and alignment of five registration categories with the BES definition.

  2. The NERC-led panel, which establishes subset lists of applicable reliability standards for registered entity functions (e.g., Under-Frequency Load Shedding-only Distribution Providers), has been incorporated into the rules.

These reforms strengthen the registration process and are important milestones in NERC's approach to managing risks to reliability. Deployment and implementation of these revisions began in 2015, with continued work in 2016 and possibly 2017.

- No further enhancements are anticipated to support the ongoing next phases of the risk-based registration activity.
- Based on the 2015 technical assessment of the Phase 2 registered functions (Transmission Operator, Transmission Owner, Generator Owner, and Generator Operator), development of subsets of standards are not necessary.
- The certification and registration programs will be assessed in 2016, which may result in modifications to the program in 2017.
- The activities associated with the implementation of the BES definition have decreased, therefore no additional resource demands are expected in the registration area.
- Planned oversight activities for 2017 will be aligned with the ERO Enterprise Operating Model and should not affect 2017 resource allocation and should have little effect on overall NERC resource requirements. NERC understands that each Regional Entity will need to evaluate its individual resource needs and allocations.

Reliability Assessment and Performance Analysis Program (RAPA)

- Support and leadership to (1) the Planning Committee and (2) standing committees' subcommittees, working groups, and task forces serving the standing committees will continue.
- NERC and the Regional Entities will continue to focus resources on high quality reliability assessments and performance analysis, including:
  - Development and implementation of expanded and enhanced enterprise-based data collection and analysis systems, and capabilities for performance analyses. This includes TADS, GADS, NERC RAS data, and misoperations data;
  - Support of the integration of RAPA information systems for assessments and associated data requirements, with focus on objective and technically sound reliability assessments supporting delivery of high quality reports (e.g., long-term, short-term, special or scenario assessments, and State of Reliability Report);

  - Development of assessment and performance analysis techniques as well as resource capabilities and tools, including probabilistic and scenario evaluations, which address the reliability impacts of new technologies, changing resource or demand resource composition, and environmental related regulations or legislation;
  - Providing technical resources and expertise to perform analyses as needed, including to support and identify risk priorities for standards development, compliance, and enforcement activities;
  - Development of appropriately tailored analysis and overall assessment, including guidance for registered entities, of high impact, low frequency BES risks, including physical security and geomagnetic disturbance (GMD) vulnerability.
  - Providing technical resources to support up to four short-term reliability assessments (6-18 month horizon replacing the current summer and winter assessments), which focus on specific reliability risk areas and geographic areas with specific reliability concerns, while also allowing for regional assessments;
  - Support of the common approach developed for NERC reliability assessments to ensure consistent treatment of resource and reliability evaluations.

- NERC and the Regional Entities will advance analytical capabilities for identifying and determining reliability risks and conducting various reliability assessments by:
  - Integrating the analysis and measures of essential reliability services (ERS) into the Long-Term Reliability Assessment. The process encompasses new data collection and analysis approaches needed to address assessment objectives of identifying reliability issues due to a changing resource mix;
  - Requiring advanced powerflow and stability analysis tools and objective expert input for transmission/deliverability assessments and studies;
  - Maturing and developing interconnection-wide analysis groups to support the assessment of interconnection-wide risks, such as frequency response;
  - Providing technical resources and reliability leadership for the advancement of probabilistic analyses supporting the Long-Term Reliability Assessment;
  - Requiring advanced statistical analysis tools and objective expert input to support them for probabilistic assessments.

- NERC will support the maintenance of the BESnet application and manage processing of the Regional BES Exception Requests (ERs), including technical validation of the definition and exception requests, self-determined notification submittals, periodic reviews of network changes affecting BES determinations, as well as requests for registration and certification reviews. The Regional Entities will continue to process BES ERs per guidelines established in the NERC Rules of Procedure.[41]

- NERC and Regional Entities' resources (through the case building designee agreements) will support the Planning Coordinators' development of long-term sustainable interconnection-wide powerflow and dynamics model cases under reliability standards MOD-032 and MOD-033 that exhibit the accuracy and fidelity reflecting actual BES reliability performance and dynamic conditions. These models will integrate needed elements that address reliability behavior of changing resource mix and technology of both generation and loads, including:

[41] NERC Rules of Procedure

  - Development of a process to ensure the continued compilation and creation of annual sets of seasonal and future steady state and dynamic simulation model cases;
  - Provision of technical resources to support the effective and continuous improvement of the models that incorporate recognition of reliability behavior of loads and generation associated with the changing resource mix;

- NERC and the Regional Entities will work collaboratively to enhance the ERO Enterprise's capability for post event analysis, including:
  - Development of a process to ensure the compilation and creation of steady state and dynamic simulation model cases for use in the investigation and analysis of major power system disturbance events;
  - Development and tracking of metrics that demonstrate the accuracy of the powerflow and dynamics models to replicate actual system conditions and reliability behavior;
  - Evaluation of event disturbances using phasor measurements and other methods to assess sufficiency of data and models.
- NERC and the Regional Entities may require contractor and consultant services to maintain continued support and technical expertise associated with activities listed in the above assumptions and with supporting special assessment, scenario, or other technical research efforts. It could potentially impact both NERC and Regional Entity resource allocation:
  - If significant events occur, contractor services may be required to support wide-area system analyses and root cause evaluations.
  - Contractor services may be necessary to support special assessment analyses (e.g., EPA 111(d) evaluation or ERS), scenario analyses (e.g., polar vortex-like severe event analyses and gas-electric interdependence), and other technical research efforts (e.g., similar to geomagnetic disturbances, and FAC-003 Vegetation Management).

Training, Education, and Operator Certification Program

- NERC will continue to budget for the unified learning management system (LMS) focused initially on Regional Entity audit staff, with near-term consideration for risk-based compliance monitoring and enforcement related staff. Future inclusion of other ERO functional areas is expected as potential requirements present themselves during system development. NERC will work with the Regional Entities to consolidate training resources and promote better coordination, planning, delivery and management of training and outreach efforts across the enterprise without adversely impacting Region-specific training requirements.
- The implementation of CMEP staff training and competencies are expected to influence the allocation of training resources throughout the enterprise. NERC will continue the development of compliance training modules with assistance of qualified subject matter experts from the Regional Entities and incorporation of outside expertise/services.
- An allocation of additional resources may be required to support certain training and outreach activities of the risk-based CMEP:
  - Regional Entities should allocate resources to meet the requirements for the compliance and enforcement staff that are associated with the implementation of the risk-based CMEP.
- The Regional Entities, in collaboration with NERC, are expected to help assess and determine training and outreach needs. This includes flexibility in approach between Regional Entities, and

anticipating areas of support for their staff and stakeholders for standards, compliance monitoring and enforcement, situation awareness and event analysis, and information technology. Addressing these needs will likely require additional resource allocation and budgeting considerations.

- NERC, in collaboration with Regional Entities, will develop and deliver additional CIP V5 training to support the transition. This may require consideration for additional funding of the NERC training and education budget.
- The Operating Personnel Certification program is expected to remain at a steady state with no additional resources required from the Regional Entities.
- Contractor and consultant services may be necessary to maintain the continued support and technical expertise associated with some enterprise training, outreach and education activities.

Situation Awareness and Infrastructure Security (including Events Analysis)

- NERC will continue to provide required support and leadership for the Operating Committee and the Critical Infrastructure Protection Committee, and standing committees, subcommittees, working groups, and task forces serving the standing committees. Regional Entity involvement is expected to remain at current levels with no additional resources required from the Regional Entities.
- Registered Entity participation in the ERO Event Analysis Process, which involves active participation by Regional Entity staffs, will continue at or above current levels through 2016.
- NERC will continue to budget and incur costs to operate and maintain the software application known as Situational Awareness for FERC, NERC, and Regional Entities, Version 2 (SAFNRv2) for situation awareness, and The Event Analysis Management System (TEAMS) for Events Analysis. The allocation of additional resource investments are expected to maintain the capabilities of SAFNRv2 throughout the planning period. Any such investments will be NERC funded and not result in an allocation of cost to the Regional Entities.
- Regional Entities will continue to budget for event analysis and situational awareness activities based on their respective Region's historical workload, as they did in the past. Some Regional Entities will continue to allocate resources as part of the activities accounted for under their RAPA program, and should clearly delineate where the activities' resources are budgeted.
- Regional Entities will support critical infrastructure security activities in the context of situation awareness, using those designated resources, unless specifically budgeted and managed elsewhere.

Electricity Information Sharing and Analysis Center (E-ISAC)

- NERC will continue to fund, operate and maintain the E-ISAC, with no increased cost to the Regional Entities.
- NERC will continue to fund and conduct the Grid Security Exercise program, with no increased cost to the Regional Entities. Analysis and planning activities will occur during even-numbered years and execution of the exercise will take place in odd-numbered years.
- NERC will continue to fund and conduct the Grid Security Conference as an annual event. Other than funding registration fees for individual attendees from their Regional Entity, no Regional Entity funding is anticipated.

Information Technology and Project Management Office (PMO)

- NERC and the Regional Entities will work collaboratively to refine existing strategies and governance and procurement practices applicable to the development, operation, and maintenance of enterprise architecture, including software and data systems supporting both NERC and Regional Entity operations.
- NERC's BP&B will include ongoing funding support for the development, operation, and maintenance of ERO Executive Management Group (EMG)-approved enterprise applications. Enterprise application funding in any given year will be subject to the budget and funding limits set forth in NERC's approved BP&B. Regional Entities should include appropriate funding for applications and supporting systems designed to satisfy Regional business needs (if not within the mutually agreed upon scope of the ERO Enterprise applications that are funded by NERC).
- Regional Entities may be required to provide or augment business teams to help develop application business requirements and to test business functionality within the ERO applications.
- Ongoing investments will be required to develop, implement, and maintain enhancements to the NERC and Regional Entity websites, ERO applications, and ERO data repositories, which are required to improve access to information and data. NERC and the Regional Entities will separately fund any enhancements to their own websites.

ERO Enterprise-wide Risk Management

- A common ERO Enterprise risk management framework commenced in 2014 to focus on identifying, assessing, prioritizing, and mitigating risks associated with the performance of both NERC and the Regional Entities. This will be a multi-year activity with the project expected to reach steady state by 2017.
- NERC's Director of Risk Management and Internal Audit is responsible for the overall development of this framework, with the approval of the ERO Regional Executives and under the oversight of NERC's Enterprise Wide Risk Management Committee.
  NERC and the Regional Entities will continue to devote resources to implement this framework. Activities include validating and prioritizing risks for EROEMG review and approval. The results will serve as an input into the NERC's future audit plans, which are reviewed and approved by the NERC Board of Trustees Enterprise Risk Management Committee. Regional Entities may add risk management and internal control resources as needed.

Exhibit B – Application of NERC Section 215 Criteria

DISCUSSION OF HOW THE NERC MAJOR ACTIVITIES IN THE 2017 BUSINESS PLAN AND BUDGET MEET THE NERC WRITTEN CRITERIA FOR DETERMINING WHETHER A RELIABILITY ACTIVITY IS ELIGIBLE TO BE FUNDED UNDER FEDERAL POWER ACT SECTION 215

Introduction

This Exhibit discusses how the major activities in NERC's 2017 Business Plan and Budget meet the NERC written criteria for determining whether a reliability activity is eligible to be funded under §215 of the Federal Power Act ("FPA §215"). This Exhibit is intended to satisfy Recommendation No. 38 resulting from the financial performance of NERC conducted by the Commission's Division of Audits ("DA") in 2012-2013 and adopted by the Commission in its November 2, 2012 order on NERC's 2013 Business Plan and Budget.[1] NERC submitted the written criteria to the Commission in a compliance filing dated February 21, 2013 in Docket No. FA11-21-000.[2] The Commission approved the NERC written criteria, with modifications, in an order issued in that docket on April 18, 2013.[3] The NERC written criteria as used in this Exhibit incorporate the modifications specified in the Compliance Order.[4]

II. Reliability Standards Program 2017 Major Activities

The major activities of the Reliability Standards Program are described at pages 24-26 of the 2017 Business Plan and Budget. The Reliability Standards Program carries out the ERO's responsibility to develop, adopt, obtain approval of, and modify as and when appropriate, mandatory Reliability Standards for the reliable planning, operation, and critical infrastructure protection of the North American BES. The major activity areas for this program include (1) providing project management and leadership to the reliability standard development process to deliver high-quality, continent-wide reliability standards, both new and modified, including standard development outreach activities, facilitation of Standard Drafting Team activities, drafting support, assisting Standard Drafting Teams in adhering to the processes in the *Standard Processes Manual*, and ensuring that the quality of documents produced are appropriate for approval by industry and the NERC Board; (2) facilitating continent-wide industry engagement in the standard development processes; and (3) conducting industry balloting on standards, disseminating information on standards and the standard development processes, and supporting regulatory filings and proceedings relating to standards. Additionally, the Reliability Standards Program provides technical advice and final quality review for Regional Entity standards development processes, presents proposed regional standards to the

[1] *North American Electric Reliability Corporation, Order Accepting 2013 Business Plan and Budget of the North American Electric Reliability Corporation and Ordering Compliance Filing*, 141 FERC ¶ 61,086 (2012) ("2013 Budget Order"). Recommendation 38, as adopted in the 2013 Budget Order, is: "In its annual business plan and budget filings, [NERC should] provide an explanation as to why the proposed activities to be undertaken by each program area for the budget year are statutory, including, at a minimum: a description and the purpose of the major activities to be taken by each program area and an explanation for why the activity is a statutory activity." *Id.* at P 16.

[2] *Compliance Filing of the North American Electric Reliability Corporation in Response to Paragraph 30 of November 2, 2012 Commission Order – NERC Written Criteria for Determining Whether a Reliability Activity is Eligible to be Funded Under Federal Power Act Section 215*, filed February 1, 2013 in Docket No. FA 11-21-000 ("February 1, 2013 Compliance Filing").

[3] *North American Electric Reliability Corporation, Order on Compliance*, 143 FERC ¶ 61,052 (2013) ("Compliance Order").

[4] For ease of reference, the complete NERC written criteria, as modified in accordance with the Compliance Order, are provided at the end of this Exhibit.

NERC Board, and prepares submissions for approval of regional standards to the applicable regulatory authorities in the U.S. and Canada.

For 2017, the major activities of the Reliability Standards Program will focus on (1) selection of standards projects to be undertaken based on the nature of the reliability issue, cost compared to risks, and whether a standard or another solution is most appropriate to address the issue; (2) addressing Commission directives and responding to Commission orders as necessary through the standards process; (3) performing enhanced periodic reviews of standards; and (4) facilitating smooth transitions to new standards through developing guidelines, webinars, and other activities to support auditor and industry training for new standards. Identification of need for new standards projects will be based on sources such as Commission directives and reliability risks identified by the Reliability Risk Management Process or the Reliability Issues Steering Committee (RISC).

The major activities of the Reliability Standards Program satisfy the following criteria:

I.A: Is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure (ROP)?

I.B: Is the activity necessary or appropriate for providing guidance and assistance to Regional Entities in carrying out Regional Reliability Standards development activities?

I.C: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated?

I.D: Is the activity necessary or appropriate for the provision of training and education concerning Reliability Standards development processes, procedures, and topics for/to (i) NERC personnel, (ii) Regional Entity personnel, (iii) industry personnel?

II.F.1: Is the activity necessary or appropriate for the provision of training, education and dissemination of information for/to (i) NERC personnel, (ii) Regional Entity personnel, and (ii) industry personnel with respect to compliance monitoring and enforcement topics and topics concerning reliability risks identified through compliance monitoring and enforcement activities, such as (1) Requirements of Reliability Standards, including how to comply and how to demonstrate compliance? This includes development of guidance and interpretation documents.

IV: Is the activity one that was required or directed by a Commission order issued pursuant to §215? (Reliability Standards development projects re often initiated in response to directives in Commission orders).

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for these major activities are §300 and Appendix 3A.)

VI: Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18

C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and applicable provisions of Commission orders?

IX. Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

X. Is the activity necessary or appropriate for the analysis and evaluation of activities encompassed by one or more of the other criteria for the purpose of identifying means of performing the activities more effectively and efficiently?

III. Compliance Monitoring and Enforcement and Organization Registration and Certification Program Area 2017 Major Activities

The major activities of the Compliance Monitoring and Enforcement and Organization Registration and Certification Program Area are described at pages 28-30, 31-33, and 35-41 of the 2017 Business Plan and Budget. This Program Area is comprised of three operational groups: (1) Compliance Assurance (addressing compliance monitoring), (2) Reliability Assurance (addressing assurance, organization registration and certification), and (3) Compliance Enforcement.

The Compliance Assurance group works collaboratively with the Regional Entities to ensure effective implementation of risk-based compliance monitoring under the Compliance Monitoring and Enforcement Program ("CMEP") across the entire ERO Enterprise. This group's activities include the following major activities and functions: (1) ensuring that Regional Entities monitor registered entities for compliance according to their specific facts and circumstances, developing customized compliance oversight plans (COPs) for each registered entity based on its inherent risk assessment (IRA); (2) overseeing Regional Entities' IRAs of registered entities; (3) oversight of the quality implementation of the risk-based compliance monitoring program; (4) development of the annual CMEP Implementation Plan; (5) oversight of use of necessary compliance-related processes, procedures, IT platforms, tools and templates; (6) development and delivery of education and training for ERO Enterprise staff; (7) conducting CIP V5 training and education programs and other outreach that support industry compliance and integration of risk assessment and internal controls; (8) coordinating with the NERC Standards department for standards development to provide compliance information, statistics, and perspectives to standard drafting teams to foster development of standards that provide increased reliability benefit and clarify compliance risks, and to assist in smooth transitions for standards from development to enforceability, including by providing draft compliance monitoring guidance, information on how compliance with draft standards will be determined, and input on auditability and enforceability; (9) supporting Regional Entity and industry committees, working groups and task forces, such as the NERC Compliance and Certification Committee; (10) industry training for every Reliability Standard approved by the Commission, as well as industry-focused outreach events and webinars on risk-based CMEP activities; and (11) promoting registered entities' development of effective compliance programs and internal controls.

The ongoing and new major activities of the Compliance Assurance group for 2017 will include: (1) continuing to mature the risk-based compliance program, including fully developing customized COPs for registered entities; (2) working with NERC Enforcement and IT and with Regional Entity staffs on improvements in the existing compliance reporting, analysis, tracking system and other compliance tools supporting risk-based activities; (3) supporting successful implementation of CIP V5 standards and subsequent enhancements that become effective in 2017 and beyond; (4) continuing to monitor and

support effective implementation and monitoring of the Physical Security Reliability Standard; (5) initiating a training program to support implementation of common audit procedures for each standard; and (6) continuing to integrate standards and compliance functions for clear stakeholder implementation, including through a common set of Reliability Standards Audit Worksheets, measures, or successors for all standards and in initiating a compliance phase-in learning period for all standards.

The Compliance Analysis, Certification and Registration group is responsible for a range of requirements and activities embodied in Section 500 and Appendices 5A and 5B of the NERC ROP, including providing technical resource support to standards development, compliance monitoring, and enforcement; ensuring that all entities impacting the BES are registered commensurate with risk; ensuring all Reliability Coordinators ("RC"), Balancing Authorities ("BA") and Transmission Operators ("TOP") are certified; conducting industry reliability assurance activities; and ensuring that compliance gaps identified in reportable events are assessed and addressed if appropriate. Major activities of this group include (1) registration of BES users, owners, and operators who are responsible for compliance with Commission-approved Reliability Standards; (2) evaluating and certification of the competency of RCs, BAs and TOPs; (3) conducting activities to reasonably assure the ERO that certain actions have been taken as reported in response to NERC Alerts or guidance to industry; (4) providing oversight of Regional Entity implementation of regional registration, compliance, certification, investigation, and complaint programs and processes; (5) conducting investigations of identify Possible Violations of Reliability Standards in response to complaints, BES disturbances, or other triggers, including participating on all Regional Entity-led investigations and observing as requested on Commission-led reliability investigations and inquiries; and (6) working with Regional Entity staff to confirm that qualified events and disturbances are evaluated against the relevant Reliability Standards and to ensure formal compliance monitoring occurs if indicated. Specific major activities of Compliance Analysis, Certification and Registration for 2017 will include continuing to work with the NERC-led panel to review registered entities for deregistration or applicability to a reduced number of Reliability Standards; and implementing registration program improvements and certification program improvements identified in 2016, including conducting training as necessary.

The Compliance Enforcement department is responsible for overseeing enforcement processes, the application of penalties or sanctions, and activities to mitigate and prevent recurrence of noncompliance with Reliability Standards. The Department works collaboratively with the Regional Entities to ensure consistent and effective implementation of the risk-based CMEP, including evaluating the consistency of disposition methods including assessment of penalties or sanctions. It also focuses on ensuring that the ERO Enterprise dedicates resources to the matters that pose the greatest risk to reliability. The Compliance Enforcement department monitors Regional Entities' enforcement processes and provides oversight over the outcomes of such processes, to ensure due process, identify best practices and process efficiency opportunities, and promote consistency among Regional Entities' business practices; collects and analyzes compliance enforcement data and trends to assist with identification of emerging risks and help to inform development of enforcement policy and processes; files notices of penalty ("NOP") and other submittals associated with noncompliance discovered through Regional Entity compliance, monitoring and enforcement activities; processes and files NOPs and other submittals discovered through NERC-led investigations and audits; collaborates with other NERC departments, including Compliance Assurance, Reliability Standards and Regional Entity Coordination; and delivers training of the ERO Enterprise staff and outreach to registered entities on compliance and enforcement topics. Compliance Enforcement also conducts outreach activities that focus on self-logging, compliance exceptions, risk elements, CIP V5, IRAs, and internal controls.

During 2017, the Compliance Enforcement department will continue to focus on the successful implementation of, as well as refining and improving, the risk-based CMEP. The major activities of Compliance Enforcement will include refining and improving risk-based CMEP processes; implementing in a transparent manner the risk-focused ERO Enterprise enforcement philosophy; expanding the feedback loop of information from Enforcement to Standards and other program areas; and working with Compliance Assurance, IT, and Regional Entity staff regarding improvements in the existing compliance, reporting, analysis system and other compliance tools to support risk-based activities.

The major activities of the Compliance Monitoring and Enforcement and Organization Registration and Certification Program Area satisfy the following criteria:

I.A: Is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure?

I.C: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated?

II.A: Is the activity necessary or appropriate for the identification and registration of users, owners, and operators of the Bulk Power System that are required to comply with Requirements of Reliability Standards applicable to the reliability functions for which they are registered?

II.B: Is the activity necessary or appropriate for the Certification of Reliability Coordinators, Transmission Operators and Balancing Authorities as having the requisite personnel, qualifications and facilities and equipment needed to perform these reliability functions in accordance with the applicable Requirements of Reliability Standards?

II.D: Is the activity necessary or appropriate for conducting, participating in or overseeing compliance monitoring and enforcement activities pursuant to the NERC ROP and (through the Regional Entities) the Commission-approved delegation agreements?

II.E: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information to monitor and enforce compliance with Reliability Standards, including evaluating the effectiveness of current compliance monitoring and enforcement processes, the need for new or revised compliance monitoring and enforcement processes, and the need for new or different means of training and education on compliance with Reliability Standards.

II.F: Is the activity necessary or appropriate for the provision of training, education and dissemination of information for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel with respect to compliance monitoring and enforcement topics and topics concerning reliability risks identified through compliance monitoring and enforcement activities, such as: (1) Requirements of Reliability Standards, including how to comply and how to demonstrate compliance? This includes development of guidance and interpretation documents. (2) Compliance monitoring and enforcement processes, including how to conduct them, how to participate in them, and the expectations for the process? This includes development of guidance documents. (3) Disseminating, through workshops, webinars,

Advisories/Recommendations/Essential Actions, and other publications, "lessons learned" information on compliance concerns and reliability risks obtained through compliance monitoring and enforcement activities, monitoring and investigation of Bulk Power System major events, off-normal occurrences and near miss events, and other Bulk Power System monitoring activities? (4) Registered Entity internal processes for compliance with Reliability Standards, such as development, implementation and maintenance of internal reliability compliance programs?

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for these major activities are §400 and 500 and Appendices 4B, 4C, 5A, 5B and 5C.)

VI: Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18 C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and applicable provisions of Commission orders?

IX: Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in the activities encompassed by one or more of the other criteria?

X: Is the activity necessary or appropriate for the analysis and evaluation of activities encompassed by one or more of the other criteria for the purpose of identifying means of performing the activities more effectively and efficiently?

IV. Reliability Assessment and System Analysis Program 2017 Major Activities

The major activities of the Reliability Assessment and System Analysis (RASA) Program are described at pages 43-47 of the 2017 Business Plan and Budget. The RASA Program carries out the ERO's responsibility to conduct assessments of the reliability and adequacy of the BES to provide insight and guidance about reliability risks and performance improvements. RASA focuses on developing a technical framework and understanding of the reliability risks facing the industry. The principal activity areas of the RASA Program include: independent assessments and reports on the overall reliability, adequacy, and associated reliability risks that could impact the upcoming summer and winter seasons and the long-term (e.g. 10-year) planning horizon; development of focused reliability assessments based on emerging reliability risks and other reliability issues garnering an in-depth analysis; performance analysis and recommendations of historical reliability and associated trends, relying on data integrity and consistent methodology, supporting credible recommendations and guidance; reliability assessment and interconnection-wide analysis for analyzing steady-state and dynamic conditions, including frequency, Essential Reliability Services, and stability aspects; support for development and improvement of long-term sustainable interconnection-based power flow, dynamic and load models, and technical studies and practices to use these models; advancement of industry and the ERO's understanding of power system characteristics and behaviors by gathering larger PMU datasets of data for advanced data analytics and modeling improvements; reliability risk program management for identifying and improving key risk areas using analyses of reliability gaps, risks, controls, and management efforts, as well as integration with the RISC, Long-Term Reliability Assessment, short-term (seasonal) assessments, and State of Reliability reports; management of reliability risk program priorities to align with the Strategic Plan and business

plan and budget for appropriate level of resources, timing, completion and execution; and establishing reliability leadership and consistent, technically sound guidance and recommendations that position industry and policy-makers to enhance reliability through effective outreach and communications.

The RASA Program works with industry leaders to create a reliability strategy that is relevant, timely, and effective at addressing the most important reliability risks, through understanding key information identified through analysis and assessment efforts; extracting and prioritizing the associated reliability risks from that information; sharing and integrating risk analysis insights across the ERO Enterprise; and translating that knowledge into actionable guidance and recommendations for NERC management, the Board, and entities, and government policy makers. Reliability assessments evaluate the expected reliability behavior of the BPS through extensive deterministic and probabilistic analyses to identify potential reliability conditions that could compromise reliability. RASA both assesses and reports on the reliability, adequacy and associated risks that could impact short-term and long-term study periods, and conducts special reliability assessments and identifies recommendations and guidance actions that may be warranted to lessen identified risks or enhance overall reliability. RASA also coordinates forecast reliability data between planning areas, the Regional Entities, and government organizations, and produces the Electricity Supply and Demand data base. A significant ongoing effort involving RASA, Regional Entity staff, and stakeholders focuses on continued development of effective Essential Reliability Services, leading to defined Essential Reliability Services, an evaluation of initial metrics and data compilation of actual performance, and ongoing assessment.

RASA works closely with other organizations such as the Electric Power Research Institute (EPRI), Department of Energy (DOE), Institute of Electrical and Electronics Engineers (IEEE), Institute of Nuclear Power Operations (INPO), North American Transmission Forum (NATF), North American Generation Forum (NAGF), Canadian Electricity Association (CEA), Interstate Natural Gas Association of America, and Natural Gas Supply Association, on a number of energy industry reliability issues such as geomagnetic disturbances, vegetation management, variable generation integration, and interdependency of gas and electric systems.

The ongoing and new major activities of the RASA Program for 2017 include: (1) Issuing assessment reliability reports, guidelines, recommendations and alerts as needed (including verification and validation of data and information through Regional Entities and technical committees); preparing the long-term (10-year) and short-term (2 to 4 seasonal or shoulder period analyses) reliability assessments; conducting special assessments addressing key reliability risks, including potential environmental regulation impacts to BPS reliability and Essential Reliability Services issues (frequency response and controls, natural gas availability and pipeline outage assessment, and nuclear plant retirements); and preparing an annual State of Reliability Report; (2) Preparing a frequency response analysis report (to the Commission and to support Reliability Standard BAL-003 and the annual Interconnection Frequency Reporting obligations (IFRO)); meeting regulatory requirements per BAL-003-1 and other analyses and studies of frequency response. (3) Supporting a risk registry and systematic prioritization process consistent with the RISC framework and supporting BES risk profile measurements and assessment of standards. (4) Executing integrated risk control strategies and plans across the ERO Enterprise to address the highest-priority existing or emerging risks to BES reliability, and explicitly measure the results. (5) Supporting Reliability Standards development and responses to Commission directives by providing technical and system analysis expertise. (6) Supporting the technical foundation development for Reliability Standards to address deficiencies or needs identified by RASA. (7) Advancing NERC's analytical capability for identifying reliability risks and conducting various reliability assessments, including by integrating Essential Reliability Services analysis and measures into long-term reliability

assessment, proving advanced power flow and stability analysis tools for transmission/deliverability assessments and studies, and providing advanced statistical tools for probabilistic assessments. (8) Providing support and leadership to the NERC Planning Committee and to standing committees and subcommittees, working groups, and task forces. (9) Assisting in the development of approaches to registration and providing input (based on reliability trends, risks, and historical performance information) to NERC staff in support of the development CMEP risk elements, to ensure that the compliance focus remains on the most critical entities and associated Reliability Standards. (10) Supporting major event investigations, analyses, and reporting of major findings, recommendations, and lessons learned that will improve reliability. (11) Building and sustaining an ERO Enterprise Reliability Assessment and Performance Analysis team that encompasses risk-informed approaches and structured methods to identify and address reliability risks. (12) Implementing effective oversight and tracking of various technical aspects of reliability, including frequency response performance, application of TPL footnote b adoption, and root cause applications, to assessments and analyses. (13) Supporting interconnection-wide model-building groups by providing feedback on model quality and fidelity. (14) Developing a Reliability Guideline on Power Plan Model Verification, including providing industry support with webinars and training, supporting the user group in the NERC Synchronized Measurement Subcommittee, and developing a structured approach to evaluate and improve system models, model validation, system analysis, and assessments. (15) Expanding use of synchrophasor technology for power plant model verification, compliance with MOD-026/-027 standards, and internal system and model analysis. (16) Broadening understanding of inter-area, local, and forced oscillations in all interconnections, and using wide-area synchrophasor data to provide industry with better understanding of phenomena, available tools, and findings. (17) Driving education of dynamic load modeling and development of improved load models, and supporting compliance with Reliability Standard TPL-001-4, including through a Reliability Guideline on Load Comparison, Technical Reference Document on Load Modeling, a workshop on Dynamic Load Modeling and FIDVR, driving next generation dynamic load models for all software platforms, model benchmarking and testing for more robust tools and models, and developing default data sets and testing with industry to ensure robust starting points. (18) Proactively seeking to address deficiencies in interconnection-wide models used by Transmission Planners and TOPs. (19) Ensuring models can sufficiently recreate plant behavior, through exploring known/historical events and required modeling improvements to accurately represent pre- and post-events. (20) Working with interconnection model designees to positively impact case quality and robustness for industry's benefit. (21) Supporting study and policy development related to end-use load behavior, and advocate for grid-friendly load response.

During 2017, RASA will continue to work with the Regional Entities on implementation of the BES definition and processing BES Exception Requests, through reviews, evaluations, and confirmations of proposed changes to BES elements by registered entities and use of the BESnet tool.

The major activities of the RASA Program satisfy the following criteria:

I.A: is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure?

I.C.1: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated, such as: (1) Measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and

analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

II.A: Is the activity necessary or appropriate for the identification and registration of users, owners, and operators of the Bulk Power System that are required to comply with Requirements of Reliability Standards applicable to the reliability functions for which they are registered?

III.A: Is the activity necessary or appropriate for the preparation or dissemination of long-term, seasonal, and special assessments of the reliability and adequacy of the Bulk Power System?

III.B: Is the activity necessary or appropriate for measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

III.F: Is the activity necessary or appropriate for the development and dissemination of Advisories/Recommendations/Essential Actions regarding lessons learned and potential reliability risks to users, owners, and operators of the Bulk Power System?

IV: Is the activity one that was required or directed by a Commission order issued pursuant to §215? (FERC orders directed NERC to develop and implement a revised definition of "Bulk Electric System" and a procedure for requesting and receiving exceptions from the BES definition, and subsequently approved NERC's proposed revised BES definition and its proposed BES exception procedure.)

V. Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for this major activity are §801-806 and 809-810 and Appendix 5C.)

VI: Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18 C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and applicable provisions of Commission orders?

IX: Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

X: Is the activity necessary or appropriate for the analysis and evaluation of activities encompassed by one or more of the other criteria for the purpose of identifying means of performing the activities more effectively and efficiently?

V. Performance Analysis 2017 Major Activities

The major activities of the Performance Analysis (PA) group are described at pages 49-51 of the 2017 Business Plan and Budget. The PA group carries out the ERO's responsibility to conduct analyses of

the reliability and adequacy of the BES, which are used to provide insight and guidance about reliability risks, performance improvements, and reliability performance issues and areas of concern, including with respect to system, equipment, entity and organizational performance that may indicate a need to develop remediation strategies, action plans, or data used to revise or retire Reliability Standards or consider new Reliability Standards. PA focuses on developing a technical framework and understanding reliability risks facing the industry.

PA collects transmission outage, generator performance, demand response, and protection and control systems misoperations data in a common format using various industry databases; this data is used to develop and report grid metrics that analyze outage frequency, duration, causes, and other factors related to transmission and generator performance and automatic power system protection and control effectiveness. Trends, findings and recommendations from PA serve as technical input to Reliability Standards and to standards project prioritization, compliance process improvements, event analyses, reliability assessment, and critical infrastructure protection efforts. In 2017, PA will add wind generator data to the data collected. The analyses and results collected and produced are reported in the annual State of Reliability Report, which in 2017 will begin to reflect post-seasonal reliability review, insights from analysis of transmission, generator, and demand response data systems, and integration of event analysis and misoperations. PA also supports the NERC System Protection & Controls Subcommittee.

PA works closely with other organizations including EPI, DOE, IEEE, INPO, NATF, NAGF, and CEA, on a number of fronts, including the Transmission Availability Data System (TADS), Generator Data Availability System (GADS), and Demand Response Availability Data System (DADS).

PA's ongoing and new major activities for 2017 will include the following: (1) Issuing reliability assessment reports, guidelines, recommendations, and alerts as needed, including verification and validation of data and information through Regional Entities and technical committees, through the annual State of Reliability Report and a frequency response analysis. (2) Overseeing TADS, GADS and TADS as well as reliability metrics and protection and control systems misoperations data, including strengthening data collection and validation processes by designing, creating, testing and implementing data-checking systems for reliability assessment, system analysis and risk analysis, and providing periodic updates on trends and measures of BES reliability. (3) Serving as the business lead and working with IT, as necessary, to have in place the required tool for GADS Wind data. (4) Supporting Reliability Standards development and responses to Commission directives by providing technical and analytical expertise. (6) Assisting in the development of approaches to registration and providing input (based on reliability trends, risks, and historical performance information) to NERC staff in support of development of CMEP risk elements and ensure that the compliance focus remains on the most critical entities and associated Reliability Standards. (7) Conducting major event investigations, analyses, and reporting of major findings, recommendations, and lessons learned that will improve reliability.

The major activities of PA satisfy the following criteria:

I.A: is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure?

I.C.1: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated, such as: (1)

Measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks? (2) Monitoring, event analysis and investigation of Bulk Power System major events, off-normal occurrences and near miss events?

II.A: Is the activity necessary or appropriate for the identification and registration of users, owners, and operators of the Bulk Power System that are required to comply with Requirements of Reliability Standards applicable to the reliability functions for which they are registered?

III.A: Is the activity necessary or appropriate for the preparation or dissemination of long-term, seasonal, and special assessments of the reliability and adequacy of the Bulk Power System?

III.B: Is the activity necessary or appropriate for measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

III.F: Is the activity necessary or appropriate for the development and dissemination of Advisories/Recommendations/Essential Actions regarding lessons learned and potential reliability risks to users, owners, and operators of the Bulk Power System?

V. Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for this major activity are §801-811 and Appendix 8.)

IX: Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

VI. Reliability Risk Management (Situation Awareness and Event Analysis) 2017 Major Activities

The major activities of the Reliability Risk Management ("RRM") group, which is comprised of the Situation Awareness Department and the Event Analysis Department, are described at pages 53-55and 57-58 of the 2017 Business Plan and Budget. The RRM group carries out the ERO's responsibility to perform assessments (including real-time and near-real-time continual awareness, detailed analysis of significant events, and longer-term broad performance assessments) of the reliability and adequacy of the BES, including identifying potential issues of concern relating to system, equipment, entity, and human performance. RRM has six primary functions: (1) BES awareness, (2) event analysis and determination of root and contributing causes, (3) assessment of human performance challenges that affect BES reliability and identification of improvement opportunities, (4) continent-wide analysis and reporting of BES performance, (5) support of the NERC Operating Committee, and (6) support of the NERC Critical Infrastructure Protection Committee. Through awareness and continuous assessment, RRM identifies potential reliability risks to the BES, analyzes events in detail, ensures that industry is well informed of system events, emerging trends, risk analysis, and lessons learned, and provides data and analysis to inform other aspects of NERC's statutory functions.

The Situation Awareness department along, with the Regional Entities, monitors BES conditions, significant occurrences and emerging risks, and threats across the 14 Reliability Coordinator regions in North America. Situation Awareness also supports development and publication of NERC Alerts and awareness products, and facilitates information sharing among industry, Regions and government during crisis situations and major system disturbances. Situation Awareness is engaged in enhancement, replacement, streamlining or modification of several reliability-related situation awareness and monitoring tools, including SAFNRv2, operation and maintenance pending replacement of the current secure alert tool, and retirement of the NERCnet – Interconnection Security Network and initiation of service using a new communication network developed, sponsored and managed by the Eastern Interconnection Data Sharing Network consortium. The Situation Awareness Department uses the following reliability-related tools to support its activities: Resource Adequacy (ACE Frequency) Tool; Inadvertent Interchange; Frequency Monitoring and Analysis Tool; Intelligent Alarms Tool; and Genscape (PowerIQ and PowerRT tools).

The ongoing and new major activities of the Situation Awareness department for 2017 include: ensuring that the ERO is aware of all BES events above a threshold of impact; enabling the sharing of information and data to facilitate wide area situational awareness; during crisis situations, facilitating the exchange of information among industry, Regions, and U.S. and Canadian governments; keeping the industry informed of emerging reliability threats and risks to the BES, including any expected actions; conducting the annual NERC Monitoring and Situational Awareness Conference and Human Performance Conference; and administering the NERC Alerts process as specified in §810 of the Rules of Procedure to issue Advisory (Level 1) Alerts on significant and emerging reliability and security related topics, and facilitate the tracking of actions specified in Recommendation (Level 2) and Essential Action (Level 3) Alerts.

The Event Analysis department performs assessments of the reliability and adequacy of the BES to identify potential issues of concern related to system, equipment, entity, and human performance that may indicate a need to develop remediation strategies, action plans, or data used to revise Reliability Standards or consider new Reliability Standards. Event Analysis conducts analyses to determine the causes of events, promptly assures tracking of corrective actions to prevent recurrence, and provides lessons learned to the industry. Event Analysis analyzes all reportable events for sequence of events, root cause, risks to reliability, and mitigation and ensures that the industry is well-informed of system events, emerging trends, risk analysis, lessons learned, and expected actions. Event Analysis conducts in-depth analyses of approximately 150 events per year on average. Additionally, Event Analysis identifies human error risks and precursor factors that allow human error to affect BES reliability, and educates industry regarding such risks, precursors, and related mitigation methods. Event analysis also supports compliance and standards training initiatives and trending and analysis to identify emerging reliability risks to the BES. Event Analysis works in collaboration with and supports the activities of other groups involved in human performance analysis including the NERC Operating Committee's Event Analysis Subcommittee, the WECC Human Performance Working Group, and others. Event Analysis also collaborates with industry groups including the NATF, NAGF, and trade associations.

The ongoing and new major activities for 2017 for the Event Analysis department include: (1) Working with Regional Entities to obtain and review information from registered entities on qualifying events and disturbances in order to advance awareness of events above a threshold level; facilitating analysis of root and contributing causes, risks to reliability, wide area assessments and remediation efforts; and disseminating information regarding events in a timely manner. (2) Ensuring that all

reportable events are analyzed for sequence of events, root cause, risk to reliability, and mitigation. (3) Continuing to refine risk-based methodologies to support better identification of reliability risks, including use of more sophisticated cause codes for analysis. (4) Ensuring consistency in reporting and analysis to support wide area assessments of significant reliability trends and risks. (5) Conducting training (webinars, workshops and conference support) to inform industry and the ERO of lessons learned, root cause analysis, trends, human performance, and cold weather preparedness and recommendations. (6) Developing reliability recommendations and alerts as needed. (7) Tracking industry accountability for critical reliability recommendations. (8) Ensuring that industry is well informed of system events, emerging trends, risk analysis, lessons learned, and expected actions. (9) Conducting major event analysis and reporting of major findings and recommendations that will improve reliability. (10) Advancing the quality and usefulness of reliability assessments and event analysis data. The Event Analysis department will also support several top priority reliability risk projects being led by the PA program.

The major activities of the RRM group satisfy the following criteria:

I.C.2: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated, such as: (2) Monitoring, event analysis and investigations of Bulk Power System major events, off-normal occurrences and near-miss events?

II.E.2: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information to monitor and enforce compliance with Reliability Standards, including evaluating the effectiveness of current compliance monitoring and enforcement processes, the need for new or revised compliance monitoring and enforcement processes, and the need for new or different means of training and education on compliance with Reliability Standards, such as: (2) Monitoring, event analysis and investigation of Bulk Power System major events, off-normal occurrences, and near miss events?

II.F.3: Is the activity necessary or appropriate for the provision of training, education and dissemination of information for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel with respect to compliance monitoring and enforcement topics and topics concerning reliability risks identified through compliance monitoring and enforcement activities, such as: (3) Disseminating, through workshops, webinars, Advisories, Recommendations, Essential Actions, and other publications; “lessons learned” information on compliance concerns and reliability risks obtained through compliance monitoring and enforcement activities; monitoring and investigation of Bulk Power System major events, off-normal occurrences and near miss events, and other Bulk Power System monitoring activities?

II.G: Is the activity necessary or appropriate for the development and provision of tools and services that are useful for the provision of adequate reliability, because they relate specifically to compliance with existing Reliability Standards and they proactively help avert Reliability Standard violations and Bulk Power System disturbances?

III.C: Is the activity necessary or appropriate for investigating, analyzing, evaluating, and disseminating information concerning, the causes of major events and off-normal occurrences, and/or providing coordination assistance, technical expertise and other assistance to users,

owners, and operators of the Bulk Power System in connection with Bulk Power System major events and off-normal occurrences, but not real-time operational control of the Bulk Power System?

III.D: Is the activity necessary or appropriate for awareness of circumstances on the Bulk Power System and to contribute to understanding risks to reliability?

III.F: Is the activity necessary or appropriate for the development and dissemination of Advisories/Recommendations/Essential Actions regarding lessons learned and potential reliability risks to users, owners, and operators of the Bulk Power System?

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for these major activities are §807, 808, 810 and 1001 and Appendix 8.)

IX. Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

VII. Electricity Information Sharing and Analysis Center 2017 Major Activities

The major activities of the Electricity Information Sharing and Analysis Center ("E-ISAC") are described at pages **Error! Bookmark not defined.**-63 of the 2017 Business Plan and Budget. The primary function of E-ISAC is to reduce cyber and physical risk to the Electricity Subsector across North America by providing unique insights, leadership and coordination, and to be the trusted, timely, actionable resource of grid risk information and analysis to enhance electric reliability. The E-ISAC facilitates sector coordination regarding physical security and cybersecurity events affecting the BES. E-ISAC analytic personnel maintain a detailed understanding of emerging vulnerabilities and threats within the broad industrial control systems community and the more focused BES community. E-ISAC manages and executes NERC's responsibilities in the Cybersecurity Risk Information Sharing Program ("CRISP") and acts as the program manager for CRISP. The purpose of CRISP is to facilitate the sharing of cyber threat information and to develop situation awareness tools that enhance the electricity sector's ability to identify, prioritize, and coordinate protection of its critical infrastructure. Finally, ES-ISAC also supports an annual grid security conference and a biennial Grid Security Exercise.

The major activities of the ES-ISAC satisfy the following criteria:

I.C.1: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated, such as: (1) Measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks? (2) Monitoring, event analysis and investigation of Bulk Power System major events, off-normal occurrences and near-miss events?

III.D: Is the activity necessary or appropriate for awareness of circumstances on the Bulk Power System and to contribute to understanding risks to reliability.

III.E: Is the activity necessary or appropriate for gathering, analyzing and sharing with and among industry and government participants, information regarding the physical or cyber security of the Bulk Power System.

III.F: Is the activity necessary or appropriate for the development and dissemination of Advisories/Recommendations/Essential Actions regarding lessons learned and potential reliability risks to users, owners, and operators of the Bulk Power System?

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for these major activities are §810 and 1003.)

IX. Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

VIII. Training, Education, and Operator Certification Program 2017 Major Activities

The major activities of the Training, Education, and Operator Certification Program are described at pages 65-68 of the 2017 Business Plan and Budget. The major activities of this program include oversight and coordination of the delivery of training programs to NERC and Regional Entity staff; as well as training and education for industry participants on the requirements of Reliability Standards, the Reliability Standards development process, and the compliance monitoring and enforcement process. The Training and Education Program supports the ERO's responsibilities to develop, adopt, and obtain approval of Reliability Standards and to monitor, enforce and achieve compliance with the mandatory standards. The Training and Education Program also supports NERC's System Operator Certification Program, which ensure that personnel operating the BES have the skills, training and qualifications needed to operate the BES reliably. This Program maintains the credentials required to work in system control centers across North America for over 6,000 system operators. The Training and Education Program prepares operators for complying with requirements of Reliability Standards and appropriately operating the BES during normal and emergency operations. Education and training activities include the following subject matter: risk-based compliance monitoring and enforcement; standards and compliance; registration and certification; event analysis, cause analysis, and lessons learned; reliability assessment and system analysis; continuing education for system operators; and new system operator certification examinations for the Reliability Coordinator, Transmission Operator, Balancing and Interchange Operator, and Balancing, Interchange and Transmission Operator credentials.

The major activities of the Training, Education, and Operator Certification Program for 2017 include providing and expanding training and education for ERO personnel and industry in the following areas: Reliability Standards compliance, emerging cyber-related issues; auditor skills and consistent audit and investigation techniques and standards compliance reviews, including risk-based compliance monitoring and enforcement and other improvements in compliance and enforcement practices; development and implementation of clear and technically sound Reliability Standards; lessons learned and trends from events, and identified themes from trending and common cause analysis; effective root,

apparent and common cause analysis methods; quality improvement of registered entity self-reporting and self-certification; entity registration processes, issues and alternatives; human performance fundamentals; and developing and incorporating a systematic approach to ongoing training. The Training, Education, and Operator Certification Program will continue to work with industry stakeholders and the System Operator Certification exam vendor to create certification exams that will promote reliability of the BPS. Further, the Continuing Education (CE) program will evaluate and revise the current program criteria as reflected in the CE program manual, taking into account the growth and maturation of industry training programs as well as ongoing research on adult learning to ensure the CE program continues to foster improvements in training and promotes quality in training programs.

The major activities of the Training, Education, and Operator Certification Program satisfy the following criteria:

I.D: Is the activity necessary or appropriate for the provision of training and education concerning Reliability Standards development processes, procedures and topics for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel?

II.C: Is the activity necessary or appropriate for the Certification of system operating personnel as qualified to carry out the duties and responsibilities of their positions in accordance with the Requirements of applicable Reliability Standards?

II.F: Is the activity necessary or appropriate for the provision of training, education and dissemination of information for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel with respect to compliance monitoring and enforcement topics and topics concerning reliability risks identified through compliance monitoring and enforcement activities, such as: (1) Requirements of Reliability Standards, including how to comply and how to demonstrate compliance? This includes development of guidance and interpretation documents. (2) Compliance monitoring and enforcement processes, including how to conduct them, how to participate in them, and the expectations for the processes? This includes development of guidance documents. (3) Disseminating, through workshops, webinars, Advisories/Recommendations/Essential Actions, and other publications, "lessons learned" information on compliance concerns and reliability risks obtained through compliance monitoring and enforcement activities, monitoring and investigation of Bulk Power System major events, off-normal occurrences and near miss events, and other Bulk Power System monitoring activities. (4) Registered Entity internal processes for compliance with Reliability Standards, such as development, implementation and maintenance of internal reliability compliance programs?

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provision for these major activities are §600 and 900.)

VI: Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18 C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and applicable provisions of Commission orders?

IX. Administrative Services 2017 Major Activities

NERC's Administrative Services Departments are Technical Committees and Member Forums (for which no funding for activities is budgeted for 2017), General and Administrative, Legal and Regulatory, Information Technology ("IT"), Human Resources, and Finance and Accounting. The major activities of these departments are described at pages 69-79 of the 2017 Business Plan and Budget.

General and Administrative includes the administration and general management of the organization, the Chief Executive Officer and Chief Reliability Officer, Board of Trustees fees and expenses, communications, external affairs and government relations, office rent, and support of the activities of the NERC Member Representatives Committee and the Regional Entity Management Group.

Legal and Regulatory provides legal support to the organization, including to management, and the Reliability Standards, Compliance Analysis and Certification and Registration, Reliability Risk Management, and RASA Programs, as well as general corporate legal support in areas including antitrust, corporate, commercial, insurance, contracts, employment, real estate, copyright, tax, and other areas.

IT supports NERC's computing, Internet, database and electronic data storage and maintenance, and telecommunications needs, programs, applications and infrastructure, including management of the development and implementation of new software applications and infrastructure. The capital expenditure projects managed by IT represent capital expenditures in hardware, software and associated tools to securely gather, store, analyze and maintain data across the ERO Enterprise to support the ERO's operations, as well as necessary acquisition and replacement of computers, servers and related devices. IT's 2017 activities are focused on NERC infrastructure and support; improving, enhancing, or replacing existing functionalities; ERO Enterprise infrastructure and support; and ERO Enterprise new functionalities.

Human Resources manages all of NERC's human resources functions, including staffing, benefits administration, employee relations, performance and compensation management, succession planning, and training and development. Human Resources also obtains compensation studies, effectiveness studies, and other compensation consulting services when needed.

Finance and Accounting manages all finance and accounting functions of NERC, including employee payroll, 401(k), 457(b) and 457(f) plans, travel and expense reporting, monthly financial reporting, sales and use tax, meetings and events planning and services, insurance, internal audit, facilities management, development of the annual business plan and budget, and the ERO risk management framework.

The major activities of NERC's Administrative Services Departments satisfy the following criteria:

I.A: Is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure (ROP)?

II.A: Is the activity necessary or appropriate for the identification and registration of users, owners, and operators of the Bulk Power System that are required to comply with Requirements of Reliability Standards applicable to the reliability functions for which they are registered?

II.D: Is the activity necessary or appropriate for conducting, participating in or overseeing compliance monitoring and enforcement activities pursuant to the NERC ROP and (through the Regional Entities) the Commission-approved delegation agreements?

III.C: Is the activity necessary or appropriate for investigating, analyzing, evaluating, and disseminating information concerning, the causes of major events and off-normal occurrences, and/or providing coordination assistance, technical expertise and other assistance to users, owners, and operators of the Bulk Power System in connection with Bulk Power System major events and off-normal occurrences, but not real-time operational control of the Bulk Power System?

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provision for the major activities of Finance and Accounting is §1100.)

VI: Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18 C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and the applicable provisions of Commission orders.

IX. Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

XI: Is the activity a governance or administrative/overhead function, activity or service necessary or appropriate for the activities encompassed by the other criteria and, in general, necessary and appropriate to operate a functioning organization?

NERC WRITTEN CRITERIA FOR DETERMINING WHETHER AN ACTIVITY IS ELIGIBLE TO BE FUNDED UNDER SECTION 215 OF THE FEDERAL POWER ACT

For purposes of internal management approval of a proposed new activity or group of related activities ("major activity"), the proposed activity or major activity must be shown to fall within at least one of the criteria listed below. When sub-criteria are listed below a roman numeral numbered major criterion, the proposed activity should be a positive answer to at least one of the sub-criteria. Conversely, an activity that falls under a sub-criterion should pertain to the subject matter of the major criterion.

NERC's annual business plan and budget will describe how each major activity falls within one or more of the criteria listed below. If the major activity is substantially the same as a major activity that was shown to fall within the criteria in a previous year's business plan and budget, the current year's business plan and budget can refer to the prior year business plan and budget.

A determination that an activity falls within FPA §215 does not necessarily mean that NERC will propose or undertake such activity. The determination of whether an activity falling under FPA §215 should or will be undertaken in a given budget year will be addressed in the context of the applicable business plan and budget and will include opportunities for stakeholder input.

The criteria listed below are not necessarily each distinct from the others. An activity or major activity may fall within more than one of the criteria listed below.

I. Is the activity necessary or appropriate for the development of Reliability Standards?

   A. Is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure (ROP)?

   B. Is the activity necessary or appropriate for providing guidance and assistance to Regional Entities in carrying out Regional Reliability Standards development activities?

   C. Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated, such as:

      1. Measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System[46] based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

      2. Monitoring, event analysis and investigation of Bulk Power System major events, off-normal occurrences and near miss events?

   D. Is the activity necessary or appropriate for the provision of training and education concerning Reliability Standards development processes, procedures and topics for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel?

II. Is the activity necessary or appropriate for the monitoring and enforcement of compliance with Reliability Standards?

   A. Is the activity necessary or appropriate for the identification and registration of users, owners, and operators of the Bulk Power System that are required to comply with

[46] This document uses the term "Bulk Power System" because that is the term defined and used in FPA §215. NERC recognizes that a different term, "Bulk Electric System," is used to define the current reach of reliability standards. Reliability Standards.

Requirements of Reliability Standards applicable to the reliability functions for which they are registered?

B. Is the activity necessary or appropriate for the Certification of Reliability Coordinators, Transmission Operators and Balancing Authorities as having the requisite personnel, qualifications and facilities and equipment needed to perform these reliability functions in accordance with the applicable Requirements of Reliability Standards?

C. Is the activity necessary or appropriate for the Certification of system operating personnel as qualified to carry out the duties and responsibilities of their positions in accordance with the Requirements of applicable Reliability Standards?[47]

D. Is the activity necessary or appropriate for conducting, participating in or overseeing compliance monitoring and enforcement activities pursuant to the NERC ROP and (through the Regional Entities) the Commission-approved delegation agreements?

E. Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information to monitor and enforce compliance with Reliability Standards, including evaluating the effectiveness of current compliance monitoring and enforcement processes, the need for new or revised compliance monitoring and enforcement processes, and the need for new or different means of training and education on compliance with Reliability Standards, such as:

1. Measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

2. Monitoring, event analysis and investigation of Bulk Power System major events, off-normal occurrences, and near miss events?

F. Is the activity necessary or appropriate for the provision of training, education and dissemination of information for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel with respect to compliance monitoring and enforcement topics and topics concerning reliability risks identified through compliance monitoring and enforcement activities, such as:

1. Requirements of Reliability Standards, including how to comply and how to demonstrate compliance? This includes development of guidance and interpretation documents.

2. Compliance monitoring and enforcement processes, including how to conduct them, how to participate in them, and the expectations for the processes? This includes development of guidance documents.

3. Disseminating, through workshops, webinars, Advisories, Recommendations, Essential Actions, and other publications; "lessons learned" information on compliance concerns and reliability risks obtained through compliance monitoring and enforcement activities; monitoring and investigation of Bulk Power System major events, off-normal occurrences and near miss events, and other Bulk Power System monitoring activities?

[47] Although certification of system operating personnel is an activity falling within the scope of, and eligible to be funded pursuant to, FPA §215, NERC strives to fully fund the costs of this activity through fees charged to participants.

4. Registered Entity internal processes for compliance with Reliability Standards, such as development, implementation and maintenance of internal reliability compliance programs?

G. Is the activity necessary or appropriate for the development and provision of tools and services that are useful for the provision of adequate reliability, because they relate specifically to compliance with existing Reliability Standards and they proactively help avert Reliability Standard violations and Bulk Power System disturbances?

III. Is the activity necessary or appropriate for conducting and disseminating periodic assessments of the reliability of the Bulk Power System or monitoring the reliability of the Bulk Power System?

A. Is the activity necessary or appropriate for the preparation or dissemination of long-term, seasonal, and special assessments of the reliability and adequacy of the Bulk Power System?

B. Is the activity necessary or appropriate for measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

C. Is the activity necessary or appropriate for investigating, analyzing, evaluating, and disseminating information concerning, the causes of major events and off-normal occurrences, and/or providing coordination assistance, technical expertise and other assistance to users, owners, and operators of the Bulk Power System in connection with Bulk Power System major events and off-normal occurrences, but not real-time operational control of the Bulk Power System?

D. Is the activity necessary or appropriate for awareness of circumstances on the Bulk Power System and to contribute to understanding risks to reliability?

E. Is the activity necessary or appropriate for gathering, analyzing and sharing with and among industry and government participants, information regarding the physical or cyber security of the Bulk Power System?

F. Is the activity necessary or appropriate for the development and dissemination of Advisories/Recommendations/Essential Actions regarding lessons learned and potential reliability risks to users, owners, and operators of the Bulk Power System?

G. Is the activity necessary or appropriate for data collection and analysis of information regarding Bulk Power System reliability matters mandated by the Commission?

IV. Is the activity one that was required or directed by a Commission order issued pursuant to FPA §215? Justification of an activity as a FPA §215 activity based on this category must reference the particular Commission order and directive.

V. Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)?

VI. Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18 C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and applicable provisions of Commission orders?

VII. Is the activity necessary or appropriate to maintain NERC's certification as the Electric Reliability Organization? This Criterion includes conducting periodic assessments of NERC's and the Regional Entities' performance as the Electric Reliability Organization as required by 18 C.F.R. §39.3(c).

VIII. Does the activity respond to or is it necessary or appropriate for audits of NERC and the Regional Entities conducted by the Commission?

IX. Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

X. Is the activity necessary or appropriate for the analysis and evaluation of activities encompassed by one or more of the other criteria for the purpose of identifying means of performing the activities more effectively and efficiently?

XI. Is the activity a governance or administrative/overhead function, activity or service necessary or appropriate for the activities encompassed by the other criteria and, in general, necessary and appropriate to operate a functioning organization? (Should NERC perform any non-FPA §215 activities, the costs of governance and administrative/overhead functions must be appropriately allocated.)
NERC's current governance and administrative/overhead functions are carried out in the following program areas:

A. Technical Committees and Members' Forum Programs

B. General and administrative (includes, but is not limited to, executive, board of trustees, communications, government affairs, and facilities and related services).

C. Legal and Regulatory.

D. Information Technology

E. Human Resources

F. Accounting and Finance.

The following matters are excluded from the scope of FPA §215 activities. While a list of non-FPA §215 activities would be infinite, the following excluded matters are listed here because they are expressly referred to in FPA §215, the Commission's ERO regulations and/or a Commission order issued pursuant to FPA §215:

A. Developing or enforcing requirements to enlarge Bulk Power System facilities, or to construct new transmission capacity or generation capacity, or requirements for adequacy or safety of electric facilities or services.

B. Activities entailing Real-time operational control of the Bulk Power System.

C. Activities pertaining to facilities used in the local distribution of electricity.

Exhibit C – Contractor and Consulting Costs

Program	Consultants & Contracts	2016 BUDGET	2017 BUDGET	2017 vs 2016 Budget
Compliance Assurance	Reliability Assurance Initiative	200,000	50,000	(150,000)
	Compliance Assurance	**200,000**	**50,000**	**(150,000)**
Event Analysis	Reliability Assurance Project Support	56,000	-	(56,000)
	Event Analysis	**56,000**	**-**	**(56,000)**
Compliance Investigation, Registration and Certification	Risk-based Registration Phase 2 - Consulting Support	50,000	-	(50,000)
	Compliance Investigation, Registration and Certification	**50,000**	**-**	**(50,000)**
Reliability Assessments and System Analysis	Reliability affects of GMD	100,000	100,000	-
	Reliability consulting support	475,000	425,000	(50,000)
	Reliability Assessments and System Analysis	**575,000**	**525,000**	**(50,000)**
Performance Analysis	GADS/TADS/DADS/SED	509,039	528,082	19,044
	Performance Analysis	**509,039**	**528,082**	**19,044**
Situation Awareness	Reliability Tools	576,300	619,150	42,850
	Secure Alerting System	141,000	96,000	(45,000)
	SAFNR - Phase II	438,200	505,700	67,500
	Communication network (NERCnet replacement)	55,975	75,000	19,025
	Situation Awareness	**1,211,475**	**1,295,850**	**84,375**
E-ISAC	**GridEx Support**	-	250,000	250,000
	Program-Level Capabilities	366,500	353,000	(13,500)
	Software & Services	113,285	113,285	-
	Events & Outreach	50,550	50,550	-
	CRISP	5,888,594	5,888,594	-
	E-ISAC and CRISP	**6,636,929**	**6,788,429**	**151,500**
System Operator Certification	System Operator Testing Expenses	59,400	62,000	2,600
	System Operator Examination Development	69,000	70,000	1,000
	Database Development	24,000	-	(24,000)
	Database Maintenance	25,200	37,800	12,600
	SOCCED Database Improvement Project (funded from Working Capital generated from fees in excess of expenses)	150,000	50,000	(100,000)
	System Operator Certification	**327,600**	**219,800**	**(107,800)**
Training and Education	Continuing Education Program	133,200	145,800	12,600
	Web-based course hosting (Learning Management System)	55,000	55,000	-
	Enhanced Platform	-	-	-
	Course development and Support - External Training	125,000	125,000	-
	NERC Staff Technical Training	35,000	35,000	-
	Continuing Education, Training & Education	**348,200**	**360,800**	**12,600**
General & Administrative	Communications support	15,000	15,000	-
	0	-	-	-
	ERO Effectiveness Survey	80,000	-	(80,000)
	General & Administrative	**95,000**	**15,000**	**(80,000)**
IT	ERO Development & Support	988,671	1,161,787	173,116
	ERO Data Analysis	100,000	200,000	100,000
	Applications Enhancements, Consulting and Help Desk Support	1,006,000	851,000	(155,000)
	Information Technology	**2,094,671**	**2,312,787**	**218,116**
HR	Training and Development	325,000	350,000	25,000
	Compensation Consulting	100,000	100,000	-
	Employee, industry and Board Surveys	50,000	50,000	-
	HR Consulting Services	75,000	75,000	-
	Human Resources	**550,000**	**575,000**	**25,000**
Finance	Internal Controls and Outside Auditor Consulting Support	200,000	300,000	100,000
	Finance and Accounting Support	97,000	97,000	-
	Finance and Accounting	**297,000**	**457,000**	**160,000**
	TOTAL CONSULTANTS AND CONTRACTS	**12,950,914**	**13,127,749**	**176,835**

Exhibit D – Capital Financing

The company successfully closed on its capital financing program on January 10, 2014. The interest rate is floating and equal to LIBOR plus 275 basis points, which yielded a rate of 2.91% at closing.[48] The total size of the non-revolving credit facility is $7.5M, with the total authorized borrowings each year limited to the amount approved by the Board of Trustees and FERC in that year's business plan and budget for IT hardware and the costs of developing software applications. Consistent with the terms of the loan documentation and its Board and FERC-approved 2014 budget, the company made an initial draw of $1.265M at the end of January 2014 related to 2013 expenditures. The company recorded new capital investments of approximately $1.65M in 2013 related to the development of software applications and IT hardware,[49] a portion of which was financed with the proceeds from this initial draw. This borrowing is amortized over three years, commencing January 31, 2014, and can be prepaid without penalty. A balance of $1.416M was available for draw during 2014, which was also consistent with NERC's 2014 approved budget. However, the company had sufficient funds available to pay for budgeted capital improvements without having to draw on this credit facility. A balance of $1.9M was available for draw during 2015, consistent with NERC's 2015 approved budget. New capital investments of $1.85 were financed with draws late in 2015 and early 2016. These new borrowings are also being amortized over three years, beginning January, 2016 and April, 2016. The company is in discussions with the lender about renewing this facility going into 2017, with terms and conditions of the renewed facility similar to those in the current agreement.

As further discussed in the Introduction and Executive Summary and in Section A, General and Administrative and set forth in the table below, NERC has a 2017 proposed capital budget of approximately $4.4M, $1.45M of which it is proposing to finance.

NERC CAPITAL BUDGET	2016	2017
ERO Application Development	$ 1,500,000	$ 700,000
E-ISAC Portal Development		1,000,000
Document Management	465,000	335,000
Hardware (Storage, servers, laptops)	955,000	991,000
Other Equipment	535,000	885,000
Disaster Recovery	200,000	150,000
NERC Software licenses	256,000	311,000
Total Capital Budget	**$ 3,911,000**	**$ 4,372,000**

The table below sets forth the projected principal and interest repayment schedule for the amounts financed to date and the additional planned $1.45M in capital financing. This projection assumes an average interest rate of 3.5% over the term of the financing, which is consistent with the 2014 budget. Management is recommending that 3.5% continue to be used given the potential for interest rate increases during 2016. The actual interest rate and interest rate expense will be reflected in the quarterly budget to actual variance reports the company posts on its website, reviews in open session with the NERC Finance and Audit Committee, and files with FERC. Any variations in interest expense will be captured and reported as a contribution to operating reserves, the expenditures of which are subject to the terms of the company's Working Capital and Operating Reserve Policy.

[48] The interest rate at closing was lower than projected for purposes of the 2014 budget. As detailed in the company's approved *2014 Business Plan and Budget*, any difference between actual and budgeted interest expense for draws under the credit facility becomes an addition to the company's Unforeseen Contingency Operating Reserve balance.

[49] This capital investment amount is exclusive of approximately $640k in expenses which were incurred in 2013 in the development of the Events Information Data System application and expensed rather than capitalized, as further discussed in the company's Q1 2014 budget variance report presented to the NERC Finance and Audit Committee.

	YEAR-END OUTSTANDING DEBT BALANCE					
	2014	**2015**	**2016**	**2017**	**2018**	**2019**
2013 Expenditure / Closed 2014	$ 878,472	$ 456,806	$ 35,139	$ -	$ -	
2015 Budgeted	-	-	1,234,547	617,274	-	
2016 Budgeted	-	-	1,500,000	666,667	333,333	
2017 Projected	-	-	-	1,450,000	966,667	483,333
2018 Projected	-	-	-	-	1,800,000	1,200,000
Total Outstanding Balance	$ 878,472	$ 456,806	$2,769,686	$2,733,940	$3,100,000	$1,683,333

	ANNUAL PAYMENTS FOR DEBT SERVICE					
	2014	**2015**	**2016**	**2017**	**2018**	**2019**
2013 Expenditure / Closed 2014	$ 386,528	$ 421,667	$ 421,667	$ 35,139	$ -	
2015 Budgeted	-	-	617,274	617,274	617,274	
2016 Budgeted	-	-	-	333,333	333,333	333,333
2017 Projected	-	-	-	-	483,333	483,333
2018 Projected	-	-	-	-	-	600,000
Interest Expense	29,367	24,826	56,529	56,725	61,170	72,203
Total Principal and Interest Costs	$ 415,895	$ 446,493	$1,095,469	$1,042,471	$1,495,110	$1,488,869

Exhibit E – Working Capital and Operating Reserve Amounts

In February 2015, the NERC Board approved an amendment to the Company's Working Capital and Operating Reserve Policy. A number of changes were made to the policy, including:

- Clarifying the definition of working capital to represent funding needed for cash flow purposes due to the timing of the receipt of funds and the payment of expenses.
- Creating four separate categories of operating reserves:
    1. A new subcategory of reserves entitled **Future Obligation Reserve** for funds that are being held to satisfy obligations that will be settled in a future year. Examples include leases, certain contracts, and credit agreements. These reserves were previously within the definition of working capital and are more accurately classified as a form of operating reserve.
    2. Continuation of a separate category of reserves for the Operator Certification Program called the **Operator Certification Reserve**.
    3. Elimination of the Known and Unforeseen Contingency categories of operating reserves and creating a single category of contingency reserves called the **Operating Contingency Reserve**.
    4. Creation of a separate category of reserves for CRISP called the **CRISP Reserve**.

Working Capital

Based on its 2016 cash flow projection and taking into account the historic manner in which NERC's assessments have been billed and paid, NERC does not anticipate needing access to working capital in 2017 to meet monthly cash flow needs. While individual reserve categories are increasing and decreasing based on operating needs and uses, the budget in total does not reflect additional net funding for reserves. In the unlikely event NERC experiences a temporary cash flow shortage, it has the ability to either request authorization from the Finance and Audit Committee and Board of Trustees to temporarily access operating contingency reserve funds, or draw on its $4M line of credit, as long as NERC is in compliance with the covenants under its bank credit agreement.

Operating Reserves

Total operating reserves are projected to be $5.5M among all four categories. The Future Obligation Reserve is budgeted to be $2.6M and is primarily funds held to offset future liabilities under lease agreements for the Atlanta and Washington, DC, offices. System Operator Certification Reserves are budgeted at $714k and the Operating Contingency Reserve is budgeted for $2.2M. The CRISP Reserve (budgeted at $500k) is held pursuant to the terms of the Master Services Agreement between NERC and participating utilities, which calls for a separate third-party funded reserve established to fund certain contingencies in connection with CRISP.

In addition to the foregoing reserves, the amended policy also provides for the creation of an **Assessment Stabilization Reserve.** The goal of the Assessment Stabilization Reserve is to mitigate assessment volatility and have changes in annual assessments track, within a reasonable band, changes in the company's total annual budget, with the total budget reflecting prudent fiscal discipline and good stewardship of resources. Assessment stabilization funds will be used when available to help stabilize assessments and mitigate year-to-year swings in assessments. Those swings primarily result from the application of penalty funds, but could also result from other factors like surplus funds available from a prior period, the need to replenish the Operating Contingency Reserve, or significant but relatively short-term operating or capital spending needs. Pending NERC Board approval of the release of restricted penalties into this reserve, the balance on January 1, 2017 will be $2.7M and has, to date, been funded entirely by penalties. NERC is proposing to use $1.1M of the balance to offset 2017 U.S. assessments. An additional penalty is expected in May 2017 for $500,000. This penalty results from a settlement reached through WECC related to the September 2011 blackout.

E-ISAC
ELECTRICITY INFORMATION SHARING AND ANALYSIS CENTER

Exhibit F - From Portal to Platform

A Capabilities Case for Improving Information Sharing in the Electricity Sector

RESILIENCY | RELIABILITY | SECURITY






Why Information Sharing Matters

- Cyber and physical threats do not come from machines
  - They originate in the minds of human adversaries
  - Cyberspace is just a tool for the adversary
  - So are explosives, weapons, truck bombs, bolt cutters and social engineering
- Threat actors typically don't work alone
  - Strategic "existential" threats (the ones we should worry about) are typified by large, well connected organizations
  - These groups routinely share, collaborate, and analyze situations freely, using every tool available including the Internet and technology
- Our challenge is to be better at sharing, collaborating, and analyzing than our adversaries
  - We need better tools than those they have

Membership Involvement

- ESCC Strategic Review (July 2015) called for continued improvement to the portal
  - Recommended the use of STIX/TAXII standards
  - Recommended the exploration of ways to automate information sharing and analysis
- Updated portal launched in September 2015
- GridEx III Simulation Deck portal used in November 2015 offered several new ideas about grid security visualization
- MEC's OTT working group developed a comprehensive list of portal improvement recommendations

Portal to Platform Timeline

- 2016:
  - Fix existing portal bugs and issues identified by the E-ISAC and members
  - Build incremental improvements to meet short-term recommendations
  - Conduct scoping/discovery effort for transition to platform
  - Validate requirements with membership
  - Launch new “look and feel” for existing portal
- 2017:
  - Install new hardware
  - Launch new platform
  - Build incremental improvements to meet long-term requirements
  - Ongoing membership feedback

Expected Benefits

- Dramatic improvement to information sharing
  - Human to human via text, discussion, document, photo, etc. sharing
  - Machine to machine via built in STIX/TAXII compatibility
- Rapid response to emerging critical situations
  - Situational awareness of physical and cyber events
  - Coordination within and external to the Electricity Sector
- Extendable as new technologies emerge
  - Easy integration with mobile technologies
  - Designed to be modular and adaptable to future capability requirements
- Increased trust in the E-ISAC
  - Will result in increased sharing and collaboration

Portal vs Platform

- Existing portal characteristics
  - Designed for a specific audience with a specific purpose
  - Static content with infrequent changes
  - No user control over look/feel of layout
  - Not designed for high levels of interaction
  - Limited search capability
- Proposed platform characteristics
  - Designed for a wide audience with different needs
  - Highly customizable by users
  - Extendable to accommodate new technologies
  - Visual and graphical orientation (vs text-based)
  - Robust search, filtering, and native language queries of datasets
  - Server-side computation and analytics

Project Management

- Total proposed 2017 budget of $1 million
- Two parallel projects
  - Near-term quick fixes and user interface improvements
  - Long-term movement to a platform with significant changes
- Project implementation managed by NERC CTO and the ERO IT PMO
- Disciplined approach used to successfully manage and implement other recent IT projects
- Ongoing MEC engagement
- Scope will be managed within approved budget

MEC Feedback

- MEC briefed at June 15, 2016 face-to-face meeting
- Bill Spence (Chairman, President and CEO, PPL Corporation, Inc. and Chair, E-ISAC Member Executive Committee) briefed EEI's Executive Committee on June 14, 2016 and provided positive feedback
- The MEC provided NERC with written comments in support of the proposed funding on or before June 30, 2016.

Agenda Item _
Board of Trustees Meeting
November 2, 2016

Rules of Procedure Revisions - Consolidated Hearing Process

Action

Approve the proposed revisions to Section 400 and Appendices 2 and 4C to the NERC Rules of Procedure (ROP) and direct staff to file the revised ROP with the appropriate regulatory authorities for approval.

Attachment 1 Redline Changes to Section 400

Attachment 2 Redline Changes to Appendix 2

Attachment 3 Redline Changes to Appendix 4C

Attachment 4 Consideration of Comments

Background

The current NERC ROP contemplate that hearings to resolve contested noncompliance, mitigation plans, remedial action directives, penalties, or sanctions may be held at each Regional Entity. NERC is proposing the introduction of a Consolidated Hearing Process, which would allow Regional Entities the *option* to move the hearing process to NERC. The proposed revisions are designed to streamline costs, enhance consistency, and increase efficiencies.

Summary of Proposed Consolidated Hearing Process

The proposed revisions include input from the Regional Entities. Under the proposed process, the consolidated Hearing Body will generally be composed of five members, including the Hearing Officer. To preserve a Regional perspective, up to two members may be nominated by the Regional Entity from which the case originates. The NERC Board of Trustees Compliance Committee (BOTCC) will appoint two members, chosen among NERC trustees not serving on the BOTCC at the time of the request for hearing. The goal is to have a balance between NERC and Regional Entity appointed Hearing Body members.

A Hearing Officer will be selected by the four Hearing Body members. If a Regional Entity chooses to appoint one or no representative, then the BOTCC will select additional members to fill those vacancies among NERC trustees not serving on the BOTCC at the time of the request for hearing. In the event a Regional Entity chooses not to appoint members to the Hearing Body and there are not four NERC trustees available to participate in the Hearing Body, as determined by the BOTCC, the Hearing Body may be composed of three members (three NERC trustees not serving on the BOTCC). If two stakeholder members are appointed by the Regional Entity, the stakeholders shall not represent the same industry segment.

To ensure that hearings are conducted in a full, fair and impartial manner, the ROP provisions governing ex parte communications that prevent communications directly or indirectly with any

person concerning any issue in the proceeding outside of the hearing process remain applicable to Hearing Body members. Hearing Body members must also be free from any applicable conflict of interest or the existence of any other circumstance that could interfere with the impartial performance of his or her duties.

Unless noted below, the conduct of the hearing under either the Regional Entity Hearing Process or the Consolidated Hearing Process would follow the existing rules, among others, relating to timing of activities, filings, service, participation, and evidence.

In addition, under either hearing process, the decision of the Hearing Body would be appealable as a matter of right to the NERC BOTCC. The appealed issues would be reviewed under a *de novo* standard, meaning the NERC BOTCC would act as if it were hearing the case for the first time, affording no deference to the Hearing Body's decision. In the Federal Energy Regulatory Commission's (FERC) order certifying NERC as the Electric Reliability Organization (ERO), FERC directed NERC to review appealed matters *de novo*.[1] The BOTCC would generally have one hundred and eighty (180) days to render its decision, subject to extension for good cause with written notice to all participants. The remaining ROP timing provisions related to Hearing Body decisions were also revised to allow for good cause extensions with notice to all participants.

Regional Entities will select either the existing Regional Entity Hearing Process or the proposed Consolidated Hearing Process. The selection will be in effect for each Regional Entity for a minimum of six months. Hearings will be conducted pursuant to the process in effect at the Regional Entity at the time the registered entity submits a hearing request. A Regional Entity may change its selected process by giving notice to NERC six (6) months prior to the change becoming effective.

Benefits of the Consolidated Hearing Process

The key benefits of the proposed Consolidated Hearing Process are increased efficiency and reduced cost to the ERO Enterprise. The proposed process allows the ERO Enterprise to centralize the hearing process, eliminating duplicative processes at the Regional Entity level. At the same time, the proposed process preserves a regional perspective by having up to two members on the Hearing Body nominated by the Regional Entity. Moreover, to the extent that the Regional Entities select this proposed Consolidated Hearing Process, it also provides the ERO Enterprise with increased consistency of process.

There are also additional cost savings from consolidated training sessions for potential Hearing Body members. Rather than each Regional Entity developing and implementing training on the hearing process to its board members and staff, there could be joint training sessions. This would also allow for consistent messaging regarding the hearing process.

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[1] "[T]he ERO should have de novo review authority on appeal in matters where consistency is desirable, such as the interpretation of standards, the application of penalty factors to specific facts, and whether the factual record supports a particular penalty or remedial action." *Order Certifying N. Am. Elec. Reliability Corp. as the Elec. Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 1,062 at P 491 (2006).

Public Comment Period

NERC posted its proposed revisions publicly on July 26, 2016 for a comment period ending on September 9, 2016. NERC received four sets of comments from industry stakeholders. The commenters suggested a consolidated Hearing Body of either five or three members to prevent impasse. Under the proposed revisions, the Hearing Body would include up to two members appointed by the Regional Entity, two NERC Trustees, and a Hearing Officer serving as the tie-breaker. This Hearing Body composition strikes the appropriate balance of adjudicators to ensure a Regional perspective is maintained.

The commenters also raised concerns regarding removing ex parte communications restrictions. Nonetheless, under the proposed revisions, there were no changes made to the rules governing ex parte restrictions. Additionally, Hearing Body members must be free from conflicts of interest and the existence of any other circumstances that could interfere with the impartial performance of his or her duties. Finally, commenters raised concerns regarding inconsistencies in the summary of the proposed revisions and ROP redlines regarding the timing provisions. For clarification, the timing provisions were revised to require written notification of any extension for good cause, not for the timing provisions to include identical timeframes.

All of the comments received are described and addressed in Attachment 4, through the hyperlink provided above. The actual submittals are also posted on the ROP page of the NERC website. Lastly, this agenda item and accompanying materials were posted on the NERC website on October 17, 2016, at least 15 days prior to consideration of these revisions by the Board of Trustees, as contemplated in NERC's process for proposed ROP revisions.

ROP Revisions

As described below, the majority of the proposed changes to ROP Sections 403, 407, 408, 409, 412, 413, and 414 relate to consistency with terminology. The proposed revisions also describe the Regional Entity Hearing Process and Consolidated Hearing Process, in addition to explicitly inserting the standard of review related to appeals and a time frame for the BOTCC to render a decision on an appeal. The disposition of certified questions is also clarified. The proposed revisions to Section 400 are summarized below.

- Section 403.4 provides that 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 selected process under Section 403.15.

- Section 403.15 would require Regional Entities to select either the Regional Entity Hearing Process or the Consolidated Hearing Process to conduct all hearings. Section 403.15 also provides that a Regional Entity may change its selected hearing process by giving notice to NERC six (6) months prior to the modification becoming effective. Sections 403.15(A) and (B), respectively, propose the composition of the Hearing Body involved in each hearing process.

- The proposed revisions to numerous Section 400 rules remove references to the defined term "Regional Entity Hearing Body" and replace it with the defined term "Hearing Body," which is discussed further below.

- Section 409.1 sets forth that the BOTCC shall render a decision to an appeal from a final decision of a Hearing Body within one hundred and eighty (180) days, subject to an extension for good cause with written notice to all participants, following the receipt by NERC's Director of Enforcement.

- Section 409.5 provides that the BOTCC would review an appeal of a Hearing Body's decision under a *de novo* standard.

- The proposed revisions to Section 412.1 added references to the "Compliance Committee" to be consistent with existing references to the "Compliance Committee" in Section 412, among other relevant provisions, including Sections 408.8, 409.5, and 414.4.

Appendix 2 (Definitions) Revisions

The proposed modifications to Appendix 2 definitions are as follows:

- "Clerk" is revised to explicitly include NERC as a Compliance Enforcement Authority that can assign an individual to perform administrative tasks relating to the conduct of hearings as described in Attachment 2, Hearing Procedures, to Appendix 4C.

- "Confirmed Violation" is modified to delete reference to the Regional Entity Hearing Body and replace it with Hearing Body.

- "Consolidated Hearing Process" is added for clarity. Consolidated Hearing Process means the process pursuant to Section 403.15B used to conduct hearings and issue decisions concerning disputed compliance maters in accordance with Attachment 2, Hearing Procedures, of Appendix 4C.

- "Director of Enforcement" is added because the ROP references Director of Enforcement, among other instances, in Section 409 (appeals from final decisions of hearing bodies) and Section 414 (appeals of decisions of hearing bodies granting or denying motions to intervene in hearing body proceedings). Director of Enforcement means the NERC Director of Enforcement or of the Compliance Enforcement Authority, as applicable, or other individual designated by the Compliance Enforcement Authority who is responsible for the management and supervision of Enforcement Staff, or his or her designee.

- "Hearing Body" is revised to mean the body designated by the Compliance Enforcement Authority to conduct hearings and issue decisions concerning disputed compliance matters in accordance with Attachment 2, Hearing Procedures, of Appendix 4C.

- "Hearing Officer" is revised to refer to, among others, an individual employed or contracted by the Compliance Enforcement Authority or NERC to preside over hearings conducted pursuant to Attachment 2, Hearing Procedures, of Appendix 4C.

Appendix 4C (Compliance Monitoring and Enforcement Program) Revisions

The proposed revisions to Appendix 4C account for both hearing processes in the hearing procedures. Among others, the following revisions were made in Appendix 4C:

- Section 1.1.1(b) was revised to reflect both hearing processes, including clarifying that Hearing Body decisions, under either hearing process, would require a majority vote to be consistent with other provisions addressing interlocutory reviews (1.4.4(e)) and Hearing Body final orders (1.7.8(b)).

- Section 1.1.4(b) regarding the interpretation of hearing procedures was deleted because it was no longer consistent with the proposed composition of hearing bodies under both hearing processes.

- The definitions contained in Section 1.1.5 were deleted and intentionally left blank because they were duplicative of the definitions contained in Appendix 2.

- Several proposed revisions relate to modifying procedural rules to incorporate both hearing processes involving issues such as the submission of documents (1.2.3), service (1.2.4), computation of time (1.2.5), location of hearings (1.2.10), disqualification (1.4.5), ex parte communications (1.4.7(b)(4)), and documents that may be withheld by staff (1.5.7(b)).

- Section 1.3.1(h) was added to explicitly incorporate the Consolidated Hearing Process in the procedural rules governing initiation of the hearing process. Likewise, Section 1.9.1(c) was added to incorporate the Consolidated Hearing Process in the initiation of a remedial action directive hearing.

- Section 1.3.4(h) regarding the shortened hearing procedure was revised to require that the Hearing Body issue a final order within one hundred and twenty (120) days of the notice of hearing, subject to an extension for good cause with written notice to all participants.

- Section 1.4.3(7) was added to provide that if the Compliance Enforcement Authority has adopted the Consolidated Hearing Process under ROP Section 403.15B, the Hearing Officer will cast the deciding vote in the event any Hearing Body vote results in a tie.

- Section 1.5.12 adds references to the "Compliance Committee" to be consistent with ROP Section 412.1 that provides that the BOTCC considers and resolves certified questions.

- Section 1.7.8(c) governing the Hearing Body final order was revised to require that the Hearing Body issue a final order within thirty (30) days following the last to occur of the initial opinion, exceptions or replies thereto, or oral argument, subject to an extension for good cause with written notice to all participants.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rules of Procedure

Effective: July 1, 2016

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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 ~~(with appropriate recusal procedures)~~ 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 segment 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 ~~should~~ 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 segment 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, provided, that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions. ~~Each Regional Entity~~

~~Compliance Monitoring and Enforcement Program shall establish and maintain 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 Regional Entity hearing process shall be conducted before 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. The Regional Entity 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 segment may veto any matter brought before the Hearing Body after recusals.~~

~~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 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.~~

15B. Consolidated Hearing Process – The Consolidated Hearing Process shall be conducted before a Hearing Body composed of four members, unless a smaller number is necessary, as discussed below, 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 segment. 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. A Hearing Officer will be selected by the Hearing Body. In the event a Regional Entity chooses not to appoint representatives to the Hearing Body and there are not four NERC trustees available to participate in 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).

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 ~~Regional Entity~~ 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 Ddirector of Eenforcement 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 ~~Regional Entity~~ 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 Ddirector of Eenforcement 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 Ddirector of Eenforcement 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 ~~Regional Entity~~ 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 ~~Regional Entity~~ 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 D~~d~~irector of E~~e~~nforcement, with copies to the Clerk, the Regional Entity, and any other Participants in the ~~Regional Entity~~ Hearing Body proceeding, no later than 21 days after issuance of the final decision of the ~~Regional Entity~~ 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 ~~Regional Entity~~ 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 ~~Regional Entity~~ Hearing Body.

3. **Response to Notice of Appeal** — Within 21 days after the date the notice of appeal is filed, the Clerk~~Regional Entity~~ shall file the entire record of the ~~Regional Entity~~ Hearing Body proceeding with NERC's D~~d~~irector of E~~e~~nforcement, with a copy to all~~the~~ Participant~~s filing the notice~~. Within 35 days after the date of the notice of appeal, all Participants in the proceeding before the ~~Regional Entity~~ 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 ~~Registered Entity~~ 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 ~~Regional Entity~~ 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 ~~Regional Entity~~ 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 ~~Regional Entity~~ Hearing Body granting or denying a motion to intervene in the ~~Regional Entity~~ Hearing Body proceeding. Appeals of decisions of ~~Regional Entity~~ Hearing Bodies granting or denying motions to intervene in ~~Regional Entity~~ 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 ~~Regional Entity~~ Hearing Bodies for Decision by the NERC Board of Trustees Compliance Committee

1. A ~~Regional Entity~~ 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 ~~Regional~~

~~Entity~~ 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 ~~Regional Entity~~ 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 ~~Regional Entity~~ 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 ~~Regional Entity~~ Hearing Body Final Decisions that Are Not Appealed

NERC shall review and process all final decisions of ~~Regional Entity~~ 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 ~~Regional Entity~~ Hearing Bodies Granting or Denying Motions to Intervene in ~~Regional Entity~~ Hearing Body Proceedings

1. **Time to Appeal** — An entity may appeal a decision of a ~~Regional Entity~~ Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** denying the entity's motion to intervene in a ~~Regional Entity~~ Hearing Body proceeding, and the Regional Entity Compliance Staff or any other Participant in the ~~Regional Entity~~ Hearing Body proceeding may appeal a decision of the ~~Regional Entity~~ Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** granting or denying a

motion to intervene in the ~~Regional Entity~~ Hearing Body proceeding, in either case by filing a notice of appeal with the NERC Ddirector of Eenforcement, with copies to the ~~Regional Entity~~ Clerk of the Hearing Body, the ~~Regional Entity~~ Hearing Bbody, the Hearing Officer, the Regional Entity Compliance Staff, and all other Participants in the ~~Regional Entity~~ Hearing Body proceeding, no later than seven (7) days following the date of the ~~Regional Entity~~ 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 ~~Regional Entity~~ 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 ~~Regional Entity~~ 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 ~~Regional Entity~~ Clerk shall transmit to the NERC Ddirector of Eenforcement copies of all pleadings filed in the ~~Regional Entity~~ Hearing Body proceeding on the motion to intervene. Within fourteen (14) days following the date the notice of appeal is filed, the ~~Regional Entity~~ Hearing Body, the Regional Entity Compliance Staff, and any other Participants in the ~~Regional Entity~~ Hearing Body proceeding, may each file a response to the notice of appeal with the NERC Ddirector of Eenforcement. Within seven (7) days following the last day for filing responses, the entity filing the notice of appeal, and any Participant in the ~~Regional Entity~~ Hearing Body proceeding that supports the appeal, may file replies to the responses with the NERC Ddirector of Eenforcement.

4. **Disposition of Appeal** — The appeal shall be considered and decided by the Compliance Committee. The NERC Ddirector of Eenforcement 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 ~~Regional Entity~~ Hearing Body granting or denying the motion to intervene shall stand. The NERC Ddirector of Eenforcement 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 ~~Regional Entity~~ Clerk, the ~~Regional Entity~~ Hearing Body, the entity filing the notice of appeal, the Regional Entity Compliance Staff, and any other Participants in the ~~Regional Entity~~ 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 ~~Regional Entity~~ Hearing Body decision granting or denying a motion to intervene in a ~~Regional Entity~~ 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

601. Scope of Personnel Certification

Maintaining the reliability of the Bulk Electric System through implementation of the Reliability Standards requires skilled, trained and qualified system operators. The Personnel Certification Program provides the mechanism to ensure system operators are provided the education and training necessary to obtain the essential knowledge and skills and are therefore qualified to operate the Bulk Electric System. The Personnel Certification awards system operator Certification Credentials to individuals who demonstrate that they have attained essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations. NERC, as the ERO, will ensure skilled, trained, and qualified system operators through the Personnel Certification Program.

Except as necessary to obtain approval of the Rules of Procedure, 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

1. The NERC Personnel Certification Program shall be international in scope.
2. The PCGC shall (1) be able to independently exercise decision-making for all matters pertaining to Certification, (2) include individuals from the discipline being certified and whose composition addresses the needs of the users of the program (e.g., employers, regulators, etc.), and (3) have representation for each specialty or level within a discipline.
3. NERC shall maintain a nominating process for membership in the governing body. Nominations shall be open to all interested parties and self-nominations shall be accepted. The NERC Board of Trustees shall appoint members to the governing body from among those nominated. The members of the governing body shall serve at the pleasure of the Board.
4. The PCGC shall have control over the matters related to the Personnel Certification and re-Certification Programs listed below, without being subject to approval by any other body.

    4.1 Policies and procedures, including eligibility requirements and application processing.

    4.2 Requirements for personnel Certification, maintaining Certification, and re-Certification.

    4.3 Examination content, development, and administration.

    4.4 Examination cut score.

4.5 Grievance and disciplinary processes.

4.6 Governing body and subgroup(s)' meeting rules including agenda, frequency, and related procedures.

4.7 Subgroup(s) appointments and work assignments.

4.8 Publications about personnel Certification and re-Certification.

4.9 Setting fees for application, and all other services provided as a part of the personnel Certification and re-Certification activities.

4.10 Program funding, spending, and budget authority. Financial matters related to the operation of the program shall be segregated from other NERC activities.

5. The Personnel Certification Program shall utilize written procedures for the selection of members of the governing body that prohibit the governing body from selecting a majority of its successors.

6. The Personnel Certification Program shall be separate from the accreditation and education functions of NERC in related disciplines.

7. No member of the PCGC or staff member working with the Personnel Certification Program governing body shall have or exercise any authority or responsibility for compliance matters related to Reliability Standards concerning personnel Certification.

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 Mechanisms

1. The Personnel Certification Program shall utilize reliable testing mechanisms to evaluate individual competence in a manner that is objective, fair to all candidates, job-related, and based on the knowledge and skill needed to function in the discipline.

2. The Personnel Certification Program shall implement a formal policy of periodic review of the testing mechanisms to ensure ongoing relevance of the mechanisms to knowledge and skill needed in the discipline.

3. The Personnel Certification Program shall utilize policies and procedures to ensure that all test administration and development materials are secure and demonstrate that these policies and procedures are consistently implemented.

4. The Personnel Certification Program shall establish pass/fail levels that protect the public with a method that is based on competence and generally accepted in the psychometric community as being fair and reasonable.

5. The Personnel Certification Program shall conduct ongoing studies to substantiate the reliability and validity of the testing mechanisms.

6. The Personnel Certification Program shall utilize policies and procedures that govern how long examination records are kept in their original format.

7. The Personnel Certification Program shall demonstrate that different forms of the testing mechanisms assess equivalent content and that candidates are not penalized for taking forms of varying difficulty.

607. Public Information About the Personnel Certification Program

1. The Personnel Certification Program shall maintain and publish publicly a System Operator Certification Program Manual describing the procedures used in examination construction and validation; all eligibility requirements and determination; fees; and examination administration documents, including: reporting of results, re-Certification requirements, and disciplinary and dispute resolution.

2. The Personnel Certification Program shall maintain and publish publicly a comprehensive summary or outline of the information, knowledge, or functions covered by each examination.

3. The Personnel Certification Program shall publish publicly and make available at least annually a summary of Certification activities for the program, including at least the following information: number of examinations delivered, the number passed, the number failed, and the number certified.

608. Responsibilities to Applicants for Certification or Re-Certification

The Personnel Certification Program:

1. Shall not discriminate among applicants as to age, gender, race, religion, national origin, disability, or marital status and shall include a statement of non-discrimination in announcements of the program.

2. Shall 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.

3. Shall 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.

4. Shall implement a formal policy for the periodic review of eligibility criteria and application procedures to ensure that they are fair and equitable.

5. Shall provide competently proctored examination sites.

6. Shall uniformly report examination results to applicants in a timely manner.

7. Shall give applicants failing the examination information on general content areas of deficiency.

609. Responsibilities to the Public and to Employers of Certified Practitioners

The Personnel Certification Program:

1. Shall demonstrate that the testing mechanisms adequately measure the knowledge and skill required for entry, maintenance, and/or advancement in the profession for each position to be certified.

2. Shall award Certification and re-Certification only after the skill and knowledge of the individual have been evaluated and determined to be acceptable.

3. Shall maintain, in an electronic format, a current list of those persons certified in the programs and have policies and procedures that delineate what information about a Credential holder may be made public and under what circumstances.

4. Shall have formal policies and procedures for discipline of a 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.

5. Shall demonstrate that any title or Credential awarded accurately reflects or applies to the practitioner's daily occupational or professional duties and is not confusing to employers, consumers, regulators, related professions, and/or other interested parties.

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

Maintaining the reliability of the Bulk Electric System through implementation of the Reliability Standards requires informed and trained personnel. The training and education program will provide the education and training necessary for Bulk Power System personnel and regulators to obtain the essential knowledge necessary to understand and operate the Bulk Electric System.

NERC shall develop and maintain training and education programs for the purpose of establishing training requirements, developing materials, and developing training activities. The target audience of the training and education programs shall be Bulk Power System operating personnel including system operations personnel, operations support personnel (engineering and information technology), supervisors and managers, training personnel, and other personnel directly responsible for complying with NERC Reliability Standards who, through their actions or inactions, may impact the real-time, or day-ahead reliability of the Bulk Power System.

NERC shall also develop and provide appropriate training and education for industry participants and regulators affected by new or changed Reliability Standards or compliance Requirements.

To accomplish those objectives:

1. NERC shall periodically conduct job task analyses for targeted Bulk Power System personnel to ensure that the training program content is properly aligned to the job tasks performed by those personnel.

2. NERC shall develop and maintain personnel training program curriculum requirements based on valid job-task analysis.

3. NERC shall periodically conduct performance surveys to determine the effectiveness of the training program and identify areas for further training development and improvement.

4. NERC shall develop training and education materials and activities to assist Bulk Power System entities implementing new or revised Reliability Standard Requirements or other NERC-related changes.

5. NERC shall develop and provide training to people who participate in NERC and Regional Entity evaluations, audits, and investigations for the Compliance Monitoring and Enforcement Program, Organization Certification Program, and the continuing education program.

902. Continuing Education Program

NERC shall develop and maintain a continuing education program to foster the improvement of training and to promote quality in the training programs used by and

implemented by Bulk Power System entities. The program shall approve or accredit those activities and entities meeting NERC continuing education requirements.

1. NERC shall develop and implement continuing education program requirements that promote excellence in training programs and advance improved performance for Bulk Power System personnel identified in Section 901.

2. NERC shall develop and maintain a process to approve or accredit continuing education Providers and activities seeking approval or accreditation and meeting NERC-approved continuing education requirements.

3. NERC shall perform periodic audits on continuing education Providers and training activities to ensure that the approved or accredited Providers and training activities satisfy NERC continuing education requirements.

4. NERC shall develop and maintain an appeals process for disputed application reviews, interpretations of guidelines and standards, probation or suspension of NERC-approved Provider status, or Continuing Education Hour disputes.

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

[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.

provided by agreement and submit funds to NERC. Alternatively, a load-serving 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.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DEFINITIONS USED IN THE RULES OF PROCEDURE

APPENDIX 2 TO THE RULES OF PROCEDURE

Effective: April 1, 2016

General

For purposes of the NERC Rules of Procedure, including all Appendices, the terms defined in this Appendix shall have the meanings set forth herein. For convenience of reference to the user, definitions of terms that are used in a particular Appendix may be repeated in that Appendix.

Where used in the Rules of Procedure, a defined term will be capitalized. Where a term defined in this Appendix appears in the Rules of Procedure but is not capitalized, the term is there being used in its ordinary and commonly understood meaning and not as defined in this Appendix (if different). Other terms that are not defined terms, such as the names of entities, organizations, committees, or programs; position titles; titles of documents or forms; section headings; geographic locations; and other terms commonly presented as proper nouns, may also be capitalized in the Rules of Procedure without being defined in this Appendix.

Definitions of terms in this Appendix that are marked with asterisks (**) are taken from the NERC *Glossary of Terms Used in Reliability Standards*. Definitions of terms in this Appendix that are marked with "pluses" (++) are taken from Section 215 of the Federal Power Act or the Commission's regulations at 18 C.F.R. Part 39 or Part 388.

Other terms used in the Rules of Procedure but not defined in this Appendix that have commonly understood and used technical meanings in the electric power industry, including applicable codes and standards, shall be construed in accordance with such commonly understood and used technical meanings.

Specific Definitions

"Acceptance of the Exception Request" or "Acceptance" means the determination that an eligible Exception Request (i.e., a Request permitted by section 4.1 of Appendix 5C) contains all the Required Information so that it can undergo substantive review.

"Adjacent Balancing Authority" means a Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.**

"Adjusted Penalty Amount" means the proposed Penalty for a violation of a Reliability Standard as determined based on application of the adjustment factors identified in Section 4.3 of the *Sanction Guidelines* to the Base Penalty Amount.

"Advisories" or "Level 1 (Advisories)" is a notification issued by NERC in accordance with Section 810.3.1 of the Rules of Procedure.

"Alleged Violation" means a Possible Violation for which the Compliance Enforcement Authority has determined, based on an assessment of the facts and circumstances surrounding the Possible Violation, that evidence exists to indicate a Registered Entity has violated a Reliability Standard.

"Annual Audit Plan" means a plan developed annually by the Compliance Enforcement Authority that includes the Reliability Standards and Registered Entities to be audited and the schedule of Compliance Audits for the calendar year.

"Annual Report" means the annual report to be filed by NERC with FERC and other Applicable Governmental Authorities in accordance with Section 13.0 of Appendix 4D.

"Applicable Governmental Authority" means the FERC within the United States and the appropriate governmental authority with subject matter jurisdiction over reliability in Canada and Mexico.

"Applicable Requirement" means a Requirement or a Requirement Part of a CIP Standard that (i) expressly provides that compliance with the terms of the Requirement or Requirement Part is required where technically feasible or (ii) is subject to Appendix 4D by FERC directive.

"Approval of the Exception Request" or "Approval" means the determination by NERC that an Exception Request meets the criteria to receive the requested Exception.

"Balancing Authority" means 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.**

"Balancing Authority Area" means the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.**

"Base Penalty Amount" means the proposed Penalty for a violation of a Reliability Standard as initially determined pursuant to Sections 4.1 and 4.2 of the NERC *Sanction Guidelines*, before application of any adjustment factors.

"BES Cyber Asset" means a Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.**

"BES Cyber System" means one or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity.**

"BES Definition" means the NERC definition of the Bulk Electric System as set forth in the NERC *Glossary of Terms Used in Reliability Standards.*

"Blackstart Resource" means a generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized

without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for Real and Reactive Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.**

"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.

"Bulk Electric System" or "BES" means unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.

- **I2** - Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
    a) Gross individual nameplate rating greater than 20 MVA. Or,
    b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.

- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.

- **I4** - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
    a) The individual resources, and
    b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

- **I5** - Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:

a) Only serves Load. Or,

b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,

c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

- **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

- **E3** - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

  a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);

  b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

  c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

- **E4** - Reactive Power devices installed for the sole benefit of a retail customer(s).

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.**

"Bulk Power System" means, depending on the context:
(i) (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and
(B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy [++]. (Note that the terms "Bulk-Power System" or "Bulk Power System" shall have the same meaning.)
(ii) Solely for purposes of Appendix 4E, Bulk Electric System.

"Canadian" means one of the following: (a) a company or association incorporated or organized under the laws of Canada, or its designated representative(s) irrespective of nationality; (b) an agency of a federal, provincial, or local government in Canada, or its designated representative(s) irrespective of nationality; or (c) a self-representing individual who is a Canadian citizen residing in Canada.

"Canadian Entity" means a Registered Entity (or, solely for purposes of Appendix 4D, a Responsible Entity) that is organized under Canadian federal or provincial law.

"Cascading" means the uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.**

"CCC" means the NERC Compliance and Certification Committee.

"Certification" means, depending on the context, (i) the process undertaken by NERC and a Regional Entity to verify that an entity is capable of responsibilities for tasks associated with a particular function such as a Balancing Authority, Transmission Operator and/or Reliability Coordinator; such Certification activities are further described in Section 500 and Appendix 5A of the NERC Rules of Procedure; or (ii) for purposes of Section 600 of the Rules of Procedure, an official recognition that indicates the recipient has passed a NERC exam or completed a specified number of Continuing Education Hours.

"Certification Staff" means individuals employed or contracted by NERC who have the authority to make initial determinations of Certification of entities performing reliability functions.

"Certification Team" means a team assembled by a Regional Entity that will be responsible for performing the activities included in the Certification process for an entity pursuant to Appendix 5A.

"CIP Senior Manager" means a single senior management official with overall authority and responsibility for leading and managing implementation of and continuing adherence to the requirements within the NERC CIP Standards, CIP-002 through CIP-011.**

"Classified National Security Information" means Required Information that has been determined to be protected from unauthorized disclosure pursuant to Executive Order No. 12958, as amended, and/or the regulations of the NRC at 10 C.F.R. §95.35; or pursuant to any comparable provision of Canadian federal or provincial law.

"Clerk" means an individual assigned by the Compliance Enforcement Authority or NERC to perform administrative tasks relating to the conduct of hearings as described in Attachment 2, Hearing Procedures, to Appendix 4C.

"Commission" means the Federal Energy Regulatory Commission or FERC.

"Complaint" means an allegation that a Registered Entity violated a Reliability Standard.

"Compliance and Certification Manager" means individual/individuals within the Regional Entity that is/are responsible for monitoring compliance of entities with applicable NERC Reliability Standards.

"Compliance Audit" means a systematic, objective review and examination of records and activities to determine whether a Registered Entity meets the Requirements of applicable Reliability Standards.

"Compliance Audit Participants" means Registered Entities scheduled to be audited and the audit team members.

"Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

"Compliance Enforcement Authority's Area of Responsibility" means the Compliance Enforcement Authority's Region. If a Regional Entity is the Compliance Enforcement Authority, the Compliance Enforcement Authority's Area of Responsibility is shown in Exhibit A to the delegation agreement between the Regional Entity and NERC.

"Compliance Exception" means a noncompliance that is addressed in Section 3A.1 of Appendix 4C, and is not pursued through an enforcement action under Section 5.0 of Appendix 4C to these Rules of Procedure by a Compliance Enforcement Authority.

"Compliance Investigation" means a comprehensive investigation, which may include an on-site visit with interviews of the appropriate personnel, to determine if a violation of a Reliability Standard has occurred.

"Compliance Monitoring and Enforcement Program" or "CMEP" means, depending on the context (1) the NERC *Uniform Compliance Monitoring and Enforcement Program* (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity

that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

"Compliant Date" means the date by which a Responsible Entity is required to be in compliance with an Applicable Requirement of a CIP Standard.

"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.

"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; or (vii) for purposes of Appendix 4D, any other information that is designated as Confidential Information in Section 11.0 of Appendix 4D.

"Confirmed Violation" means an Alleged Violation for which (1) the Registered Entity has accepted or not contested the Notice of Alleged Violation and Penalty or Sanction or other notification of the Alleged Violation, or (2) there has been the issuance of a final order from NERC or a ~~Regional Entity~~ Hearing Body finding a violation, Penalty or sanction, or (3) the period for requesting a hearing or an appeal has expired, or (4) the Registered Entity has executed a settlement agreement pursuant to Section 5.6.

"Consolidated Hearing Process" means the process pursuant to Section 403.15B used to conduct hearings and issue decisions concerning disputed compliance matters in accordance with Attachment 2, Hearing Procedures, of Appendix 4C.

"Continuing Education Hour" or "CE Hour" means based on sixty clock minutes, and includes at least fifty minutes of participation in a group or self-study learning activity that meets the criteria of the NERC Continuing Education Program.

"Continuing Education Program Provider" or "Provider" means the individual or organization offering a learning activity to participants and maintaining documentation required by Section 600 of the Rules of Procedure.

"Coordinated Functional Registration" means where two or more entities (parties) agree in writing upon a division of compliance responsibility among the parties for one or more Reliability Standard(s) applicable to a particular function, and/or for one or more Requirement(s)/sub-Requirement(s) within particular Reliability Standard(s).

"Covered Asset" means any BES Cyber Asset, BES Cyber System, Protected Cyber Asset, Electronic Access Control or Monitoring System, or Physical Access Control System that is subject to an Applicable Requirement.

"Credential" means a NERC designation that indicates the level of qualification achieved (i.e., reliability operator; balancing, interchange, and transmission operator; balancing and interchange operator; and transmission operator).

"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.++

"Critical Infrastructure Protection Standard" or "CIP Standard" means any of NERC Reliability Standards CIP-002 through CIP-011, CIP-014, and any other Reliability Standard included in the Critical Infrastructure Protection group of Reliability Standards that is adopted by the NERC Board of Trustees according to the NERC *Bylaws* and *Rules of Procedure* and approved by Applicable Governmental Authorities.

"Cross-Border Regional Entity" means a Regional Entity that encompasses a part of the United States and a part of Canada or Mexico.++

"Cyber Assets" means programmable electronic devices, including hardware, software, and data in those devices.**

"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.++

"Cyber Security Incident Information" means any information related to, describing, or which could be used to plan or cause a Cyber Security Incident.

"Days", as used in Appendix 5A with respect to the Registration and Certification processes, means calendar days.

"Deactivation," as used in Appendix 5A with respect to the Registration processes, refers to removal of an entity from the NCR for a specific functional category. As a result of deactivation, the entity is no longer subject to any prospective compliance obligations with respect to Reliability Standards applicable to that functional category.

"Delegate" means a person to whom the CIP Senior Manager of a Responsible Entity has delegated authority pursuant to Requirement R4 of CIP Standard CIP-003 (or any successor provision).

"Director of Compliance" means the Director of Compliance of NERC or of the Compliance Enforcement Authority, as applicable, or other individual designated by the Compliance Enforcement Authority who is responsible for the management and supervision of Compliance Staff, or his or her designee.

"Director of Enforcement" means the Director of Enforcement of NERC or of the Compliance Enforcement Authority, as applicable, or other individual designated by the Compliance Enforcement Authority who is responsible for the management and supervision of Enforcement Staff, or his or her designee.

"Disapproval of the Exception Request" or "Disapproval" means the determination by NERC that an Exception Request does not meet the criteria to receive the requested Exception.

"Distribution Factor" means the portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).**

"Distribution Provider" means the entity that 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.**

"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 in the United States, subject to Commission review. The organization may also have received recognition by Applicable Governmental Authorities in Canada and Mexico to establish and enforce Reliability Standards for the Bulk Power Systems of the respective countries.

"Electronic Access Control or Monitoring Systems" means 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.**

"Electronic Access Point" means 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.**

"Electronic Security Perimeter" means the logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.**

"Element" means any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.**

"Eligible Reviewer" means a person who has the required security clearances or other qualifications, or who otherwise meets the applicable criteria, to have access to Confidential Information, Classified National Security Information, NRC Safeguards Information or Protected FOIA Information, as applicable to the particular information to be reviewed.

"End Date" means the last date of the period to be covered in a Compliance Audit.

"Essential Actions" or "Level 3 (Essential Actions)" is a notification issued by NERC in accordance with Section 810.3.3 of the Rules of Procedure.

"Evidentiary Hearing" means a hearing at which one or more Participants submits evidence for the record. A Testimonial Hearing is an Evidentiary Hearing, but an Evidentiary Hearing does not necessarily include the presentation of testimony by witnesses in person.

"Exception" means either an Inclusion Exception or an Exclusion Exception.

"Exception Procedure" means the procedure set forth in Appendix 5C.

"Exception Report" means information provided to the Compliance Enforcement Authority by a Registered Entity indicating that a violation of a Reliability Standard has occurred (e.g., a System Operating Limit has been exceeded) or enabling the Compliance Enforcement Authority to ascertain the Registered Entity's compliance.

"Exception Request" means a request made by a Submitting Entity in accordance with Appendix 5C for an Exception.

"Exception Request Form" means the form adopted by each Regional Entity, in accordance with a template provided by NERC, for use by Submitting Entities in submitting Exception Requests; provided, that the Exception Request Form must include Section III.B as adopted by NERC.

"Exclusion Exception" means a determination that an Element that falls within the BES Definition should be excluded from the BES.

"Facility" means a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)**

"FERC" means the United States Federal Energy Regulatory Commission.

"Final Penalty Amount" means the final, proposed Penalty for violation of a Reliability Standard, determined in accordance with the *Sanction Guidelines*.

"Find, Fix, Track and Report" or "FFT" means a streamlined process, addressed in Section 5.2A of Appendix 4C, to resolve minimal or moderate risk, remediated Possible Violations that are not assessed a financial penalty.

"Flowgate" means 1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.**

"FOIA" means the U.S. Freedom of Information Act, 5 U.S.C. §552.

"Footprint" means the geographical or electric area served by an entity.
"Functional Entity" means an entity responsible for a function that is required to ensure the Reliable Operation of the electric grid as identified in the NERC Reliability Standards.

"Generator Operator" means the entity that operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services.

"Generator Owner" means an entity that owns and maintains generating Facility(ies).

"Hearing Body" ~~or "Regional Entity Hearing Body"~~ means the body ~~established or~~ designated by the Compliance Enforcement Authority to conduct hearings and issue decisions concerning disputed compliance matters in accordance with Attachment 2, Hearing Procedures, of Appendix 4C.

"Hearing Officer" means, depending on the context, (i) an individual employed or contracted by the Compliance Enforcement Authority or NERC ~~and designated by the Compliance Enforcement Authority~~ to preside over hearings conducted pursuant to Attachment 2, Hearing Procedures, of Appendix 4C, or (ii) 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 Appendix 4E.

"Hearing Procedures" means, depending on the context, (i) Attachment 2 to the NERC or a Regional Entity CMEP, as applicable, or (ii) the hearing procedures of the NERC Compliance and Certification Committee in Appendix 4E.

"Inclusion Exception" means a determination that an Element that falls outside the BES Definition should be included in the BES.

"Inherent Risk Assessment" or "IRA" means a review by the Compliance Enforcement Authority of potential risks posed by an individual Registered Entity to the reliability of the Bulk Power System. An IRA considers factors such as, but is not limited to, assets, system, geography, interconnectivity, prior compliance history and factors unique to the Registered Entity. The results of an entity-specific IRA may result in the scope of compliance monitoring for a particular Registered Entity to include more, fewer, or different Reliability Standards than those contained in the annual Implementation Plans.

"Interactive Remote Access" means 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. 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.**

"Interchange" means energy transfers that cross Balancing Authority boundaries.**

"Interchange Authority" means the 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.**

"Interchange Distribution Calculator" means the mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.**

"Interchange Schedule" means an agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.**

"Interchange Transaction" means an agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.**

"Interconnected Operations Service" means a service (exclusive of basic energy and Transmission Services) that is required to support the Reliable Operation of interconnected Bulk Electric Systems.**

"Interconnection" means 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.**

"Interconnection Reliability Operating Limit" means a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.**

"Intermediate System" means 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.**

"Internal Control Evaluation" or "ICE" means a review by the Compliance Enforcement Authority of a Registered Entity's internal controls. The ICE may further refine the compliance oversight plan, including the scope of an audit, the type and application of compliance monitoring tools, the depth and breadth of a particular area of review.

"Interpretation" means an addendum to a Reliability Standard, developed in accordance with the NERC *Standard Processes Manual* and approved by the Applicable Governmental Authority(ies), that provides additional clarity about one or more Requirements in the Reliability Standard.

"ISO/RTO" means an independent transmission system operator or regional transmission organization approved by the FERC or the Public Utility Commission of Texas.

"Joint Registration Organization" means an entity that registers in the Compliance Registry to perform reliability functions for itself and on behalf of one or more of its members or related entities for which such members or related entities would otherwise be required to register.

"Lead Entity" means the entity that submits Exception Request information that is common to a group of Submitting Entities that are submitting Exception Requests jointly.

"Lead Mediator" means a member of a mediation team formed pursuant to Appendix 4E who is selected by the members to coordinate the mediation process and serve as the mediation team's primary contact with the Parties.

"Load" means an end-use device or customer that receives power from the electric system.**

"Load-Serving Entity" means an entity that secures energy and Transmission Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.**

"Mapping" means the process of determining whether a Regional Entity's Footprint is being served by Registered Entities.

"Material Change" means a change in facts that modifies Required Information in connection with an approved TFE. Examples of a Material Change could include, but are not limited to an

increase in device count (but not a decrease), change in compensating measures, change in statement of basis for approval for the TFE, a change in the TFE Expiration Date, or a Responsible Entity achieving Strict Compliance with the Applicable Requirement.

"Material Change Report" means a report submitted by the Responsible Entity to the Regional Entity in the event there is a Material Change to the facts underlying an approved TFE pursuant to Section 4.0 of Appendix 4D.

"Mediation Settlement Agreement" means a written agreement entered into by the Parties to a mediation pursuant to Appendix 4E that resolves the dispute.

"Member" means a member of NERC pursuant to Article II of its Bylaws.

"Member Representatives Committee" or "MRC" means the body established pursuant to Article VIII of the NERC Bylaws.

"Mexican Entity" means a Registered Entity that is organized under Mexican law.

"Mitigating Activities" means actions taken by a Registered Entity to correct and prevent recurrence of a noncompliance, whether or not the actions are embodied in a Mitigation Plan.

"Mitigation Plan" means an action plan developed by the Registered Entity to (1) correct a violation of a Reliability Standard and (2) prevent re-occurrence of the violation.

"NERC-Approved Learning Activity" means training that maintains or improves professional competence and has been approved by NERC for use in its Continuing Education Program.

"NERC Compliance Monitoring and Enforcement Program Implementation Plan" or "NERC Implementation Plan" means the annual NERC Implementation Plan that identifies the risk elements to prioritize risks to the Bulk Power System. These risk elements and related NERC Reliability Standards and Requirements become inputs for Regional Entities in developing their Regional Compliance Monitoring and Enforcement Program Implementation Plans and the compliance oversight for individual Registered Entities. The NERC Implementation Plan may be updated more often than annually as needed.

"NERC Compliance Registry," "Compliance Registry" or "NCR" means a list, maintained by NERC pursuant to Section 500 of the NERC Rules of Procedure and Appendix 5B, the NERC *Statement of Compliance Registry Criteria*, of the owners, operators and users of the Bulk Power System, and the entities registered as their designees, that perform one or more functions in support of reliability of the Bulk Power System and are required to comply with one or more Requirements of Reliability Standards.

"NERC Identification Number" or "NERC ID" means a number given to NERC Registered Entities that will be used to identify the entity for certain NERC activities. Corporate entities may have multiple NERC IDs to show different corporate involvement in NERC activities.

"NERC Organization Certification" or "Organization Certification" means the process undertaken by NERC and a Regional Entity to verify that a new entity is capable of responsibilities for tasks associated with a particular function such as a Balancing Authority, Transmission Operator, and/or Reliability Coordinator; such certification activities are further described in Section 500 and Appendix 5A of the NERC Rules of Procedure.

"Net Energy for Load" or "NEL" means net generation of an electric system plus energy received from others less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage of energy at energy storage facilities.

"Notice of Alleged Violation and Proposed Penalty or Sanction" means a notice issued by the Compliance Enforcement Authority to a Registered Entity pursuant to Section 5.3 of Appendix 4C.

"Notice of Completion of Enforcement Action" means a notice issued by the Compliance Enforcement Authority to a Registered Entity, pursuant to Section 5.10 of Appendix 4C, stating than an enforcement action is closed.

"Notice of Confirmed Violation" means a notice issued by the Compliance Enforcement Authority to a Registered Entity confirming the violation of one or more Reliability Standards.

"Notice of Penalty" means a notice prepared by NERC and filed with FERC, following approval by NERC of a Notice or other notification of Confirmed Violation or a settlement agreement, stating the Penalty or sanction imposed or agreed to for the Confirmed Violation or as part of the settlement.

"Notice of Possible Violation" means a notice issued by the Compliance Enforcement Authority to a Registered Entity that (1) states a Possible Violation has been identified, (2) provides a brief description of the Possible Violation, including the Reliability Standard Requirement(s) and the date(s) involved, and (3) instructs the Registered Entity to retain and preserve all data and records relating to the Possible Violation.

"NRC" means the United States Nuclear Regulatory Commission.

"NRC Safeguards Information" means Required Information that is subject to restrictions on disclosure pursuant to 42 U.S.C. §2167 and the regulations of the NRC at 10 C.F.R. §73.21-73.23; or pursuant to comparable provisions of Canadian federal or provincial law.

"Open Access Transmission Tariff" means an electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.**

"Owner" means the owner(s) of an Element or Elements that is or may be determined to be part of the BES as a result of either the application of the BES Definition or an Exception, or another

entity, such as an operator, authorized to act on behalf of the owner of the Element or Elements in the context of an Exception Request.

"Participant" means a Respondent and any other Person who is allowed or required by the Hearing Body or by FERC to participate as an intervenor in a proceeding conducted pursuant to the Hearing Procedures, and as used in the Hearing Procedures shall include, depending on the context, the members of the Compliance Staff that participate in a proceeding or the members of the Certification Staff that participate in a proceeding pursuant to Appendix 4E.

"Party" or "Parties" means a Person or the Persons participating in a mediation pursuant to Appendix 4E.

"Penalty" means and 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 Registered Entity or 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 Registered Entity's or Respondent's violation and take into consideration any timely efforts made by the Registered Entity or Respondent to remedy the violation.

"Periodic Data Submittals" means modeling, studies, analyses, documents, procedures, methodologies, operating data, process information or other information to demonstrate compliance with Reliability Standards and provided by Registered Entities to the Compliance Enforcement Authority on a time frame required by a Reliability Standard or an ad hoc basis.

"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.

"Planning Authority" means the responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.**

"Physical Access Control Systems" means Cyber Assets that control, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.**

"Physical Security Perimeter" means 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.**

"Point of Delivery" means a location that a Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.**

"Point of Receipt" means a location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a generator delivers its output.**

"Possible Violation" means the identification, by the Compliance Enforcement Authority, of a possible failure by a Registered Entity to comply with a Reliability Standard that is applicable to the Registered Entity.

"Preliminary Screen" means an initial evaluation of evidence indicating potential noncompliance with a Reliability Standard has occurred or is occurring, conducted by the Compliance Enforcement Authority for the purpose of determining whether a Possible Violation exists, and consisting of an evaluation of whether (1) the entity allegedly involved in the potential noncompliance is registered, (2) the Reliability Standard Requirement to which the evidence of potential noncompliance relates is applicable to a reliability function for which the entity is registered, and (3) if known, the potential noncompliance is not a duplicate of a Possible Violation or Alleged Violation which is currently being processed.

"Probation" means a step in the disciplinary process pursuant to Section 605 of the Rules of Procedure during which the certificate is still valid. 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.

"Protected Cyber Asset" means 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 Electronic Security Perimeter.**

"Protected FOIA Information" means Required Information, held by a governmental entity, that is subject to an exemption from disclosure under FOIA (5 U.S.C. §552(e)), under any similar state or local statutory provision, or under any comparable provision of Canadian federal or provincial law, which would be lost were the Required Information to be placed into the public domain.

"Protection System" means protective relays which respond to electrical quantities, communications systems necessary for correct operation of protective functions, voltage and current sensing devices providing inputs to protective relays, station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.**

"Purchasing-Selling Entity" means 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.**

"Reactivation" refers to re-registration pursuant to the NERC Rules of Procedure Section 500 and Appendices 5A and 5B of an entity to the NCR for a specific functional category or the revocation of, or additions to, a sub-set list of Reliability Standards (which specifies Reliability Standards and may specify Requirements/sub-Requirements) that has been granted to an entity. Reactivation may be initiated by NERC, a Regional Entity or an entity with respect to such entity's own functional categories or sub-set list of Reliability Standards (which specifies Reliability Standards and may specify Requirements/sub-Requirements).

"Reactive Power" means the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive Power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive Power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).**

"Real Power" means the portion of electricity that supplies energy to the Load.**

"Receiving Entity" means NERC or a Regional Entity receiving Confidential Information from an owner, operator, or user of the Bulk Power System or from any other party.

"Recommendation" for purposes of Appendix 5C means the report to NERC containing the evaluation prepared in accordance with section 5.2 of Appendix 5C concerning whether or to what extent an Exception Request should be approved.

"Recommendations" or "Level 2 (Recommendations)" is a notification issued by NERC in accordance with Section 810.3.2 of the Rules of Procedure.

"Region" means the geographic area, as specified in a Regional Entity's delegation agreement with NERC, within which the Regional Entity is responsible for performing delegated functions.

"Regional Criteria" means reliability requirements developed by a Regional Entity that are necessary to implement, to augment, or to comply with Reliability Standards, but which are not Reliability Standards. Such Regional Criteria may be necessary to account for physical differences in the Bulk Power System but are not inconsistent with Reliability Standards nor do they result in lesser reliability. Such Regional Criteria are not enforceable pursuant to NERC-delegated authorities, but may be enforced through other available mechanisms. Regional Criteria may include specific acceptable operating or planning parameters, guides, agreements, protocols or other documents.

"Regional Entity" means an entity having enforcement authority pursuant to 18 C.F.R. § 39.8.++

"Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan" or "Regional Implementation Plan" means an annual Regional Entity plan, submitted on or about October 1 of each year to NERC for approval that, in accordance with NERC Rule of Procedure Section 401.6 and the NERC Implementation Plan, includes (1) details on regional risk assessment processes and results; (2) Reliability Standards and Requirements associated with

regional risk assessment results; (3) the methods to be used by the Regional Entity for reporting, monitoring, evaluation, and assessment of performance criteria; and (4) the Regional Entity's Annual Audit Plan.

"Regional Reliability Standard" means a type of Reliability Standard that is applicable only within a particular Regional Entity or group of Regional Entities. A Regional Reliability Standard may augment, add detail to, or implement another Reliability Standard or cover matters not addressed by other Reliability Standards. Regional Reliability Standards, upon adoption by NERC and approval by the Applicable Governmental Authority(ies), shall be Reliability Standards and shall be enforced within the applicable Regional Entity or Regional Entities pursuant to delegated authorities or to procedures prescribed by the Applicable Governmental Authority.

"Registered Ballot Body" means that aggregation of all entities or individuals that qualify for one of the Segments approved by the Board of Trustees, and are registered with NERC as potential ballot participants in the voting on proposed Reliability Standards.

"Registered Entity" means an owner, operator, or user of the Bulk Power System, or the entity registered as its designee for the purpose of compliance, that is included in the NERC Compliance Registry.

"Registration" or "Organization Registration" means the processes undertaken by NERC and Regional Entities to identify which entities are responsible for reliability functions within the Regional Entity's Region.

"Rejection of the Exception Request" or "Rejection" means the determination that an Exception Request is not an eligible Exception Request (i.e., a Request permitted by section 4.1 of Appendix 5C) or does not contain all the Required Information in accordance with section 4.5 of Appendix 5C in order to be reviewed for substance.

"Reliability Coordinator" means 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.**

"Reliability Coordinator Area" means the collection of generation, transmission and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.**

"Reliability Standard" means a requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for Reliable Operation of the Bulk Power System. The term includes requirements for the operation of existing Bulk

Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.++ (In certain contexts, this term may also refer to a "Reliability Standard" that is in the process of being developed, or not yet approved or recognized by FERC or an applicable governmental authority in other jurisdictions.)

"Reliability Standards Development Plan" means the forward-looking plan developed by NERC on an annual basis setting forth the Reliability Standards development projects that are scheduled to be worked on during the ensuing three-year period, as specified in Section 310 of the Rules of Procedure.

"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 cybersecurity incident, or unanticipated failure of system elements.++

"Remedial Action Directive" means an action (other than a Penalty or sanction) required by a Compliance Enforcement Authority that (1) is to bring a Registered Entity into compliance with a Reliability Standard or to avoid a Reliability Standard violation, and (2) is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat.

"Reporting Entity" means an entity required to provide data or information requested by NERC or a Regional Entity in a request for data or information pursuant to Section 1600 of the Rules of Procedure.

"Requirement" means an explicit statement in a Reliability Standard that identifies the functional entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each Requirement shall be a statement with which compliance is mandatory.

"Required Date" means the date given a Registered Entity in a notice from the Compliance Enforcement Authority by which some action by the Registered Entity is required.

"Required Information" means, as applicable, either (i) the information required to be provided in a TFE Request, as specified in Section 4.0 of Appendix 4D; or (ii) the information required to be provided in an Exception Request, as specified in section 4.0 of Appendix 5C.

"Requirement Part" means a component of a Requirement that is designated by a decimal number (e.g., Requirement R1 could have Requirement Parts 1.1, 1.2 and 1.3).

"Reserve Sharing Group" means a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be

expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group.**

"Resource Planner" means 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.**

"Respondent" means, depending on the context, the Registered 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, or the Registered Entity that is the subject of the Certification decision that is the basis for a proceeding under Appendix 4E.

"Responsible Entity" means an entity that is registered for a reliability function in the NERC Compliance Registry and is responsible for complying with any Requirement, or Requirement Part.

"Revoked" means a NERC certificate that has been suspended for more than twelve months. While in this state, a certificate holder can not perform any task that requires an operator to be NERC-certified. The certificate holder will be required to pass an exam to be certified again. Any CE Hours accumulated prior to or during the revocation period will not be counted towards Credential Maintenance.

"Revoke for Cause" means a step in the disciplinary process pursuant to Section 605 of the Rules of Procedure during which the certificate is no longer valid and requiring successfully passing an exam to become certified. However, an exam will not be authorized until the revocation period expires. CE Hours earned before or during this revocation period will not be counted for maintaining a Credential.

"Scope of Responsibility" means the registered functions of a Planning Authority, Reliability Coordinator, Transmission Operator, Transmission Planner or Balancing Authority and the geographical or electric region in which the Planning Authority, Reliability Coordinator, Transmission Operator, Transmission Planner or Balancing Authority operates to perform its registered functions, or with respect to a Regional Entity, its Regional Entity Region.

"Section I Required Information" means Required Information that is to be provided in Section I of a Submitting Entity's Exception Request.

"Section II Required Information" means Required Information that is to be provided in Section II of a Submitting Entity's Exception Request.

"Section III Required Information" means Required Information that is to be provided in Section III of a Submitting Entity's Exception Request.

"Sector" means a group of Members of NERC that are Bulk Power System owners, operators, or users or other persons and entities with substantially similar interests, including governmental

entities, as pertinent to the purposes and operations of NERC and the operation of the Bulk Power System, as defined in Article II, Section 4 of the NERC Bylaws. Each Sector shall constitute a class of Members for purposes of the New Jersey Nonprofit Corporation Act.

"Segment" means one of the subsets of the Registered Ballot Body whose members meet the qualification criteria for the subset.

"Self-Certification" means an attestation by a Registered Entity that it is compliant or non-compliant with a Reliability Standard Requirement that is the subject of the Self-Certification, or that it does not own Facilities that are subject to the Reliability Standard Requirement, or that the Reliability Standard Requirement is not applicable to the Registered Entity.

"Self-Logging" means a process by which Registered Entities found to be eligible by a Compliance Enforcement Authority, after a formal review of internal controls, record possible noncompliance on a log, in accordance with Section 3.5A of Appendix 4C, in lieu of individually submitted Self-Reports of each possible noncompliance.

"Self-Report" means a report by a Registered Entity stating that the Registered Entity believes it has, or may have, violated a Reliability Standard.

"Sink Balancing Authority" means the Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.**

"Source Balancing Authority" means the Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.**

"Special Protection System" means an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. A Special Protection System does not include (a) underfrequency or undervoltage Load shedding or (b) fault conditions that must be isolated, or (c) out-of-step relaying (not designed as an integral part of a Special Protection System).**

"Spot Check" means a process in which the Compliance Enforcement Authority requests a Registered Entity to provide information (1) to support the Registered Entity's Self-Certification, Self-Report, or Periodic Data Submittal and to assess whether the Registered Entity complies with Reliability Standards, or (2) as a random check, or (3) in response to operating problems or system events.

"Staff" or "Compliance Staff" means individuals employed or contracted by NERC or the Compliance Enforcement Authority who have the authority to make initial determinations of compliance or violation with Reliability Standards by Registered Entities and associated Penalties and Mitigation Plans.

"Strict Compliance" means compliance with the terms of an Applicable Requirement without reliance on a Technical Feasibility Exception.

"Submitting Entity" means (i) an owner, operator, or user of the Bulk Power System or any other party that submits information to NERC or a Regional Entity that it reasonably believes contains Confidential Information or, (ii) solely for purposes of Appendix 5C, the entity that submits an Exception Request in accordance with section 4.0 of Appendix 5C.

"Suspended" means certificate status due to an insufficient number of CE Hours being submitted prior to the expiration of a certificate. While in this state, a certificate holder can not perform any task that requires an operator to be NERC-certified.

"System" means a combination of generation, transmission and distribution components.**

"System Operating Limit" means 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).**

"Technical Advisor" means any Staff member, third-party contractor, or industry stakeholder who satisfies NERC's or the Compliance Enforcement Authority's (as applicable) conflict of interest policy and is selected to assist in a proceeding by providing technical advice to the Hearing Officer and/or the Hearing Body or Hearing Panel.

"Technical Feasibility Exception" or "TFE" means an exception from Strict Compliance with the terms of an Applicable Requirement on grounds of technical feasibility or technical limitations in accordance with one or more of the criteria in section 3.0 of Appendix 4D.

"Technical Review Panel" means a panel established pursuant to section 5.3 of Appendix 5C.

"Termination of Credential" means a step in the disciplinary process pursuant to Section 605 of the Rules of Procedure whereby a Credential is permanently Revoked.

"Testimonial Hearing" means an Evidentiary Hearing at which the witness or witnesses on behalf of one or more Participants appears in person to present testimony and be subject to cross-examination.

"TFE Expiration Date" means the date on which an approved TFE expires.

"TFE Request" means a request submitted by a Responsible Entity in accordance with Appendix 4D for an exception from Strict Compliance with an Applicable Requirement.

"TFE Termination Date" means the date, as specified in a notice disapproving a TFE Request or terminating an approved TFE, on which the disapproval or termination becomes effective.

"Transmission" means an interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.**

"Transmission Customer" means 1. any eligible customer (or its designated agent) that can or does execute a Transmission Service agreement or can and does receive Transmission Service. 2. Any of the following entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.

"Transmission Operator" means the entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.**

"Transmission Owner" means the entity that owns and maintains transmission Facilities.**

"Transmission Planner" means 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.**

"Transmission Service" means services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.**

"Transmission Service Provider" means the entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.**

"Variance" means an aspect or element of a Reliability Standard that applies only within a particular Regional Entity or group of Regional Entities, or to a particular entity or class of entities. A Variance allows an alternative approach to meeting the same reliability objective as the Reliability Standard, and is typically necessitated by a physical difference. A Variance is embodied within a Reliability Standard and as such, if adopted by NERC and approved by the Applicable Governmental Authority(ies), shall be enforced within the applicable Regional Entity or Regional Entities pursuant to delegated authorities or to procedures prescribed by the Applicable Governmental Authority.

"Violation Risk Factor" or "VRF" means a factor (lower, medium or high) assigned to each Requirement of a Reliability Standard to identify the potential reliability significance of noncompliance with the Requirement.

"Violation Severity Level" or "VSL" means a measure (lower, moderate, high or severe) of the degree to which compliance with a Requirement was not achieved.

"Wide Area" means the entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

North American Electric Reliability Corporation

Compliance Monitoring and Enforcement Program

APPENDIX 4C TO THE RULES OF PROCEDURE

Effective: May 4, 2016

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COMPLIANCE MONITORING AND ENFORCEMENT PROGRAM

1.0 INTRODUCTION

This Compliance Monitoring and Enforcement Program ("Compliance Program") is the program to be used by the North American Electric Reliability Corporation ("NERC") and the Regional Entities to monitor, assess, and enforce compliance with Reliability Standards within the United States. Compliance Monitoring and Enforcement Programs also will be implemented in Canada consistent with Canadian laws and agreements.

1.1 Definitions

Capitalized terms used in this Compliance Program shall have the meanings set forth in Appendix 2 of the NERC Rules of Procedure.

2.0 IDENTIFICATION OF ORGANIZATIONS RESPONSIBLE FOR COMPLYING WITH RELIABILITY STANDARDS

NERC shall register the organizations responsible for complying with Reliability Standards, in accordance with Section 500 of the NERC Rules of Procedure and Appendix 5B, *Statement of Compliance Registry Criteria*. Organizations are responsible to register and to comply with Reliability Standards if they are owners, operators, and users of the Bulk Power System, perform a function listed in the functional types identified in Section II of Appendix 5B, and are material to the Reliable Operation of the Bulk Power System as defined by the criteria and notes in Appendix 5B. Regional Entities shall (i) develop and provide to NERC information to assist NERC to register organizations responsible for complying with Reliability Standards, and (ii) in the event of a Registration appeal to NERC or an Applicable Governmental Authority, provide information requested by NERC concerning how the Registered Entity meets the Registration criteria or is otherwise material to the reliability of the Bulk Power System.

NERC shall notify organizations of their inclusion on the NERC Compliance Registry and shall maintain the NERC Compliance Registry on its web site. NERC shall inform each Registered Entity at the time of Registration of the Reliability Standards that are applicable to reliability functions for which the Registered Entity is registered. Each Registered Entity shall inform NERC or the applicable Regional Entity promptly of changes to the Registered Entity's Registration information including planned or completed changes in ownership of Bulk Power System Facilities, Registration status, address and other contact information, and name of designated compliance contact. NERC will provide FERC and Applicable Governmental Authorities monthly updates to the NERC Compliance Registry.

NERC and each Regional Entity will designate a contact person(s) and require each Registered Entity to designate a contact person(s) responsible for sending and receiving all necessary information and communications concerning compliance matters. NERC and the applicable Regional Entity will designate where Registered Entities are to send information, data, Mitigation Plans, or any other compliance-related correspondence.

NERC shall maintain on its website a current listing of Reliability Standards that are applicable to all Registered Entities.

As provided for herein, during the course of compliance monitoring and enforcement activities relating to U.S. entities, NERC may obtain information that it will provide to FERC and, if the information pertains to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, to such other Applicable Governmental Authority. Any such provision of information to FERC or to another Applicable Governmental Authority shall be in accordance with Section 8.0, Reporting and Disclosure.

3.0 COMPLIANCE MONITORING PROCESSES

NERC, with input from the Regional Entities, stakeholders, and regulators, shall at least annually identify risk elements and related NERC Reliability Standards and Requirements to be considered in the annual NERC Compliance Monitoring and Enforcement Program Implementation Plan (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 continent-wide risks to the reliability of the Bulk Power System. These identified risks represent the focus for oversight activities in the upcoming year, and become inputs for developing oversight plans for individual Registered Entities.

The Compliance Enforcement Authority will monitor Registered Entities' compliance with Reliability Standards using the compliance monitoring processes described in this Section. A Compliance Enforcement Authority will determine the type and frequency of application of the compliance monitoring tools appropriate for a particular Registered Entity based on the Registered Entity's specific risks to the reliability of the Bulk Power System.

If a compliance monitoring process described in this Section reveals a potential noncompliance with a Reliability Standard, the Compliance Enforcement Authority will conduct a Preliminary Screen of the potential noncompliance in accordance with Section 3.8. In addition, if the Compliance Enforcement Authority obtains evidence or information of a potential noncompliance with a Reliability Standard through any other means, including but not limited to an Exception Report or other report of noncompliance that a Registered Entity is required to submit in accordance with the terms of a Reliability Standard, the Compliance Enforcement Authority will conduct a Preliminary Screen of the information in accordance with Section 3.8. If the Preliminary Screen results in an affirmative determination with respect to the Preliminary Screen criteria, a Possible Violation exists and the Compliance Enforcement Authority will proceed in accordance with Section 5.0, Enforcement Actions, except as otherwise authorized in these Rules of Procedure.

Registered Entities found in violation of a Reliability Standard will be required to mitigate the violation regardless of any enforcement actions taken.

The compliance monitoring processes in this Section require timely information, reports and data from Registered Entities to effectively monitor compliance with Reliability Standards. The

Compliance Enforcement Authority has authority to collect Documents, data and information in the manner it deems most appropriate, including requesting copies of Documents, data and information to be made and removing those copies from the Registered Entity's location in accordance with appropriate security procedures conforming to Section 1500 of the Rules of Procedure and other safeguards as appropriate in the circumstances to maintain the confidential or other protected status of the Documents, data and information, such as information held by a governmental entity that is subject to an exemption from disclosure under the United States Freedom of Information Act, or a comparable state or provincial law, that would be lost of the information were placed into the public domain. If Documents, data, information or other reports to determine compliance requested from a Registered Entity are not received by the Required Date, the Compliance Enforcement Authority may execute the steps described in **Attachment 1, Process for Non-submittal of Requested Data.**

Parties engaged in the process described in this section should consult with each other on the data and information that would be appropriate for effectively addressing this section's process requirements. If a Registered Entity believes that a request for Documents, data or information is unreasonable, the Registered Entity may request a written determination from the NERC general counsel.

Any report or other submission of information by a Registered Entity required by the Compliance Program shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity. Electronic signatures are permitted in accordance with processes established by NERC and the Regional Entity. NERC or the Compliance Enforcement Authority may require the signer to provide a statement of the basis of his or her authority to sign on behalf of the Registered Entity.

3.1 Compliance Audits

All Registered Entities are subject to audit for compliance with all Reliability Standards applicable to the functions for which the Registered Entity is registered. Compliance Audits are conducted on the Registered Entity's site to the extent required by NERC Rule of Procedure 403.11.2. Compliance Audit processes for Compliance Audits conducted in the United States shall be based on professional auditing standards recognized in the U.S., which may include for example Generally Accepted Auditing Standards, Generally Accepted Government Auditing Standards and standards sanctioned by the Institute of Internal Auditors. Compliance Audit processes for Compliance Audits conducted outside the U.S. may be based on Canadian or other international standards. All Compliance Audits shall be conducted in accordance with audit guides established for the Reliability Standards included in the Compliance Audit, consistent with accepted auditing guidelines as approved by NERC. The audit guides will be posted on NERC's website.

3.1.1 Compliance Audit Process Steps

The process steps for a Compliance Audit are as follows:

- The Compliance Enforcement Authority posts the Annual Audit Plan (developed in coordination with NERC). The Compliance Enforcement Authority provides additional information to the Compliance Audit Participants, including Compliance Audit materials,

coordinating agendas and changes to the Compliance Audit schedule as required. NERC or the Regional Entity provides the Compliance Audit schedules to FERC and to any other Applicable Governmental Authority based upon the agreements in place with the other Applicable Governmental Authority.

- At least ninety (90) days prior to commencement of a regularly scheduled Compliance Audit, the Compliance Enforcement Authority notifies the Registered Entity of the Compliance Audit and the Reliability Standards to be evaluated, identifies the Compliance Audit team members and their recent employment history, and requests data, including a completed NERC pre-Compliance Audit questionnaire. If the Compliance Audit team members change from the time of the original notification, the Compliance Enforcement Authority will promptly notify the Registered Entity of the change and will allow time for the Registered Entity to object to the new Compliance Audit team member(s) (see Section 3.1.5.4).

- The Registered Entity provides to the Compliance Enforcement Authority the required information in the format and by the Required Date specified in the request.

- The Compliance Audit team reviews the submitted information for conformance with the Requirements of the Reliability Standards.

- The Compliance Audit team conducts an exit briefing with the Registered Entity, provides for a review of the Compliance Audit report with the Registered Entity before it is finalized, and completes a Compliance Audit report in accordance with Section 3.1.6.

- If the Compliance Audit Team identifies evidence of a potential noncompliance with a Reliability Standard Requirement by the Registered Entity, the Compliance Enforcement Authority conducts a Preliminary Screen of the potential noncompliance in accordance with Section 3.8.

3.1.2 Compliance Enforcement Authority Annual Audit Plan and Schedule

The Compliance Enforcement Authority shall develop an Annual Audit Plan. The Annual Audit Plan of Regional Entities will be included in the Regional Implementation Plans submitted to NERC for review and approval (see Section 4.2). NERC or the Regional Entity provides the Annual Audit Plans to FERC and to any other Applicable Governmental Authority consistent with the agreements in place with the Applicable Governmental Authority.

Prior to October 1 of the year preceding the year covered by the Annual Audit Plan, the Compliance Enforcement Authority shall notify Registered Entities subject to Compliance Audits during the upcoming year of the Compliance Audit schedule. The Compliance Enforcement Authority will give due consideration to any schedule changes requested by Registered Entities for reasonable cause.

Revisions and additions to a Regional Entity Annual Audit Plan shall be communicated to and approved by NERC, and shall be communicated to the Registered Entity in a timely manner

(normally sixty (60) days in advance) of changes or revisions to scheduled Compliance Audit dates.

3.1.3 Frequency of Compliance Audits

The Compliance Enforcement Authority will perform comprehensive Compliance Audits as required by the NERC Rules of Procedure and based on criteria established by NERC. In addition to scheduled Compliance Audits, the Compliance Enforcement Authority (i) may initiate an unscheduled Compliance Audit of any Registered Entity at any time if the Compliance Enforcement Authority reasonably determines it to be necessary to ensure the Registered Entity's compliance with Reliability Standards, and (ii) shall initiate an unscheduled Compliance Audit if directed by FERC. The Compliance Enforcement Authority shall notify NERC and FERC prior to or on the same date it notifies the Registered Entity that an unscheduled Compliance Audit is being initiated. If NERC initiates the unscheduled Compliance Audit, it shall notify the appropriate Regional Entity or Entities. The Compliance Enforcement Authority shall provide at least ten (10) business days advance notice to the Registered Entity that an unscheduled Compliance Audit is being initiated, which notice shall include identification of the members of the Compliance Audit team.

3.1.4 Scope of Compliance Audits

3.1.4.1 Reliability Standards

A Compliance Audit shall include those Reliability Standards applicable to the Registered Entity that are determined through the NERC approved risk-based processes described herein, and may include other Reliability Standards applicable to the Registered Entity whether or not they are identified in the Regional Entity's Regional Implementation Plan for the current year.

Regional Entities will tailor the final scope of any Compliance Audit based on the results of the Registered Entity's Inherent Risk Assessment and, if applicable, taking into consideration the results of an Internal Controls Evaluation. Except as otherwise required in the Rules of Procedure, the Compliance Enforcement Authority may use any process herein, in addition to, or in lieu of a Compliance Audit to monitor compliance with Reliability Standards.

3.1.4.2 Period Covered

The Registered Entity's data and information must show compliance with the Reliability Standards that are the subject of the Compliance Audit for the entire period covered by the Compliance Audit. The Compliance Enforcement Authority will indicate the beginning and End Date of the audit period in its notice of the Compliance Audit. The audit period begins the day after the End Date of the prior Compliance Audit by the Compliance Enforcement Authority (or the later of June 18, 2007 or the date the Registered Entity became subject to Reliability Standards if the Registered Entity has not previously been subject to a Compliance Audit). The audit period will not begin prior to the End Date of the previous Compliance Audit. The Compliance Enforcement Authority may modify the beginning date of the audit period for any given Reliability Standard Requirement based on an intervening compliance monitoring process. The End Date should be a specified date prior to the scheduled start of the Compliance Audit,

such as the date of the notification issued to the Registered Entity pursuant to Section 3.1.1 or the date that is thirty (30) days following the date of the notification.

The Registered Entity will be expected to demonstrate compliance for the entire period described above. If a Reliability Standard specifies a document retention period that does not cover the entire period described above, the Registered Entity will not be found in noncompliance solely on the basis of the lack of specific information that has rightfully not been retained based on the retention period specified in the Reliability Standard. However, in such cases, the Compliance Enforcement Authority will require the Registered Entity to demonstrate compliance through other means. In addition, if the Compliance Audit team discovers a potential noncompliance occurring subsequent to the End Date, the potential noncompliance will be subject to a Preliminary Screen pursuant to Section 3.8.

3.1.4.3 Review of Mitigating Activities

The Compliance Audit may include a review of any Mitigating Activities which the Registered Entity has not yet completed, for the purpose of determining whether the Registered Entity is making adequate progress towards completion of the Mitigating Activities.

3.1.5 Conduct of Compliance Audits

3.1.5.1 Composition of Compliance Audit Teams

The Compliance Audit team shall be comprised of members whom the Compliance Enforcement Authority has determined have the requisite knowledge, training and skills to conduct the Compliance Audit. The Compliance Audit team may include (i) contractors and industry subject matter experts, (ii) NERC staff members (which may include contractors to NERC), (iii) compliance staff members of other Regional Entities, and (iv) representatives of FERC and other Applicable Governmental Authorities so long as the Registered Entity is subject to the Applicable Governmental Authority's reliability jurisdiction. The Compliance Audit team leader shall be a staff member from the Compliance Enforcement Authority and is responsible for the conduct of the Compliance Audit and preparation of the Compliance Audit report.

3.1.5.2 Requirements for Compliance Audit Team Members

Each Compliance Audit team member must:

- Be free of conflicts of interests in accordance with the Compliance Enforcement Authority policies. Employees or contractors of the Registered Entity being audited shall not be allowed to participate as auditors in the Compliance Audit of the Registered Entity.

- Comply with the NERC Antitrust Compliance Guidelines and shall have either signed appropriate confidentiality agreements or acknowledgments that the confidentiality agreement signed by the Compliance Enforcement Authority is applicable.

- Successfully complete all NERC or NERC-approved Regional Entity auditor training applicable to the Compliance Audit.

- Prior to the Compliance Audit, the Compliance Enforcement Authority shall provide confirmation to the Registered Entity that all Compliance Audit team members have executed confidentiality agreements or acknowledgements.

3.1.5.3 Compliance Audit Observers and Other Attendees

In any Regional Entity Compliance Audit of a Registered Entity, in addition to the Compliance Audit team members, the following may participate as observers: (i) NERC Staff (which may include contractors to NERC); (ii) other members of the Regional Entity's Compliance Staff; (iii) with the permission of the Regional Entity, Compliance Staff members of other Regional Entities; and (iv) representatives of FERC and of other Applicable Governmental Authorities so long as the Registered Entity is subject to the Applicable Governmental Authority's reliability jurisdiction. Any members of NERC staff, Regional Entity Compliance Staff, or Compliance Staffs of other Regional Entities or representatives of FERC or other Applicable Governmental Authorities who are not Compliance Audit team members identified pursuant to Section 3.1.1 are observers.

In addition, at the request of the Registered Entity being audited, the Regional Entity may allow attendance at the Compliance Audit by: (1) representatives of corporate affiliates of the Registered Entity being audited that are Registered Entities or that provide compliance services, support or oversight to the Registered Entity being audited, and (2) representatives of Registered Entities whose compliance activities are conducted by the Registered Entity being audited or by the same corporate entity that conducts the compliance activities of the Registered Entity being audited (e.g., representatives of other members of a Joint Registration Organization or of participants in a Coordinated Functional Registration pursuant to Section 500 of the Rules of Procedure). Each such additional attendee must execute a confidentiality agreement approved by the Regional Entity.

Compliance Audit observers and attendees are not Compliance Audit team members and do not participate in conducting the Compliance Audit or in making Compliance Audit findings and determinations.

The Compliance Audit team leader or other staff of the Regional Entity conducting the Compliance Audit will communicate in advance with any observers or other attendees to ensure there are no undue disruptions to the Compliance Audit, such as space limitations, no conflicts of interest, and no other considerations that in the judgment of the Compliance Audit team leader may be detrimental to the conduct and quality of the Compliance Audit. If the Compliance Audit team leader identifies any such issues, he/she shall work with the proposed observers or attendees to facilitate observation in a less disruptive manner; or, alternatively, the Regional Entity Compliance staff will work with the proposed observers or attendees to schedule their participation in, observation of, or attendance at a different Compliance Audit in which such issues are not presented.

3.1.5.4 Registered Entity Objections to Compliance Audit Team

A Registered Entity subject to a Compliance Audit may object to any member of the Compliance Audit team on grounds of a conflict of interest or the existence of other circumstances that could

interfere with the team member's impartial performance of his or her duties. Any such objections must be provided in writing to the Compliance Enforcement Authority no later than fifteen (15) days prior to the start of on-site Compliance Audit work. This fifteen (15) day requirement shall not apply where a Compliance Audit team member has been appointed less than twenty (20) days prior to the start of on-site Compliance Audit work, in which case the Registered Entity must provide any objections to the Compliance Enforcement Authority within five (5) business days after receiving notice of the appointment of the Compliance Audit team member.

In the case of an unscheduled Compliance Audit pursuant to Section 3.1.3, the Registered Entity must provide any objections to the Compliance Enforcement Authority at least five (5) business days prior to the start of on-site Compliance Audit work for the unscheduled Compliance Audit.

The Compliance Enforcement Authority will make a final determination on whether the member will participate in the Compliance Audit of the Registered Entity. Nothing in Section 3.1 shall be read to limit the participation of NERC staff in the Compliance Audit or to limit the participation of FERC staff in a Compliance Audit of a Registered Entity, or involving a portion of the Bulk Power System, over which FERC has jurisdiction.

3.1.6 Compliance Audit Reports

The Compliance Audit team shall develop a draft Compliance Audit report that shall include a description of the objective, scope, and methodology of the Compliance Audit; identify any evidence of potential noncompliance with Reliability Standards by the Registered Entity found by the Compliance Audit team; identify any Remedial Action Directives, Mitigation Plans or other Mitigating Activities which have been completed or pending in the year of the Compliance Audit; and identify if any Confidential Information has been redacted. The report may also state areas of concern and recommendations identified by the Compliance Audit team. The draft report will be provided to the Registered Entity for comment.

The Compliance Audit team considers corrections based on comments of the Registered Entity, finalizes the Compliance Audit report, and provides the Registered Entity with a copy of the final report on or before the date the final report is provided to NERC. The Compliance Enforcement Authority provides the final report to NERC, which in turn provides the report to FERC if the report pertains to a Registered Entity or to a portion of the Bulk Power System over which FERC has jurisdiction and/or to another Applicable Governmental Authority if the report pertains to a Registered Entity or to a portion of the Bulk Power System over which the other Applicable Governmental Authority has jurisdiction. The provision of the final Compliance Audit report to FERC or to another Applicable Governmental Authority shall be in accordance with Section 8.0, Reporting and Disclosure. Work papers and other documentation associated with the Compliance Audit shall be maintained by the Compliance Enforcement Authority in accordance with NERC or Regional Entity requirements.

NERC will not publicly post the final Compliance Audit report for at least five (5) business days following receipt. If the Compliance Audit report identifies any Possible Violations of one or more Reliability Standards, the final Compliance Audit report, or pertinent part thereof identifying the Possible Violations, shall not be released to the public by NERC until (i) the Possible Violation is dismissed prior to becoming a Confirmed Violation, or (ii) NERC submits a

Notice of Penalty to FERC or other Applicable Governmental Authority, or (iii) the Registered Entity executes a settlement agreement with the Compliance Enforcement Authority pursuant to Section 5.6.

Information deemed by a Compliance Enforcement Authority or the Registered Entity as Critical Energy Infrastructure Information or Confidential Information shall be redacted from any public reports.

3.2 Self-Certifications

The Compliance Enforcement Authority may require Registered Entities to self-certify their compliance with Reliability Standards.

3.2.1 Self-Certification Process Steps

The process steps for the Self-Certification process are as follows:

- The Compliance Enforcement Authority posts and updates the reporting schedule containing the applicable reporting periods and informs Registered Entities. The Compliance Enforcement Authority and NERC will ensure that the appropriate Reliability Standards, compliance procedures, and required submittal forms for the Reliability Standards being evaluated are maintained and available.

- The Compliance Enforcement Authority requests the Registered Entity to make a Self-Certification within the advance notice period specified by the Reliability Standard. If the Reliability Standard does not specify the advance notice period, this request will be issued in a timely manner (normally thirty (30) days advance notice).

- The Registered Entity provides the required information to the Compliance Enforcement Authority in the form and manner, and by the Required Date, specified by the Compliance Enforcement Authority. The Self-Certification response may state that (i) the Registered Entity is in compliance with the Reliability Standard Requirement, (ii) the Registered Entity is not in compliance with the Reliability Standard Requirement, (iii) the Registered Entity does not own Facilities that are subject to the Reliability Standard Requirement, or (iv) the Reliability Standard requirement is not applicable to the Registered Entity.

- At a minimum, the Compliance Enforcement Authority reviews Self-Certifications of non-compliance and Self-Certifications in which the Registered Entity has responded that it does not own Facilities that are subject to the Reliability Standard Requirement or that the Reliability Standard Requirement is not applicable to the Registered Entity and the Compliance Enforcement Authority may request additional data and/or information if necessary.

- If the Compliance Enforcement Authority's review of the Self-Certification indicates a potential noncompliance with a Reliability Standard by the Registered Entity, the Compliance Enforcement Authority conducts a Preliminary Screen of the potential noncompliance in accordance with Section 3.8.

Receipt of a Self-Certification by the Compliance Enforcement Authority shall not be construed as a finding by the Compliance Enforcement Authority that the Registered Entity is compliant with, not compliant with, subject to, or not subject to, the Reliability Standard Requirement.

3.3 Spot Checks

Spot Checks will be conducted by the Compliance Enforcement Authority. Spot Checks may be initiated at the discretion of the Compliance Enforcement Authority or as directed by NERC at any time to verify or confirm Self-Certifications, Self-Reports, and Periodic Data Submittals. Spot Checks may also be random or may be initiated in response to events, as described in the Reliability Standards, or to operating problems, or system events.

3.3.1 Spot Check Process Steps

The process steps for Spot Checking are as follows:

- The Compliance Enforcement Authority shall issue a notification letter to the Registered Entity that a Spot Check will be performed, the reason for the Spot Check, and the scope of the Spot Check including the Reliability Standard Requirements that will be covered, in accordance with the advance notice period specified by the Reliability Standard. If the Reliability Standard Requirement does not specify an advance notice period, any information submittal request made by the Compliance Enforcement Authority will allow at least twenty (20) days for the Registered Entity to submit the information or make it available for review.

- The Compliance Enforcement Authority, as part of the notification package, shall provide the Registered Entity with the names and employment histories of the persons who will be conducting the Spot Check. The Compliance Enforcement Authority shall provide confirmation to the Registered Entity that the members of the Spot Check team have executed confidentiality agreements or acknowledgements. The Registered Entity may object to inclusion of any individual on the Spot Check team on the grounds specified in Section 3.1.5.4. Any such objections must be submitted to the Compliance Enforcement Authority by the later of (i) five (5) business days before the information being requested by the Compliance Enforcement Authority is submitted and (ii) five (5) business days after the Registered Entity is notified of the persons on the Spot Check team. Nothing in Section 3.1 shall be read to limit the participation of NERC staff in a Spot Check or to limit the participation of FERC staff in a Spot Check of a Registered Entity, or involving a portion of the Bulk Power System, over which FERC has jurisdiction.

- The Spot Check may require submission of data, documentation, and information and an on-site review.

- The Registered Entity provides the required information to the Compliance Enforcement Authority in the format and by the Required Date specified in the request.

- The Spot Check Team conducts a review of the information submitted to determine compliance with the Reliability Standards Requirements and may request additional data and/or information if necessary.

- If the Spot Check team's review of the information submitted indicates a potential noncompliance with a Reliability Standard Requirement by the Registered Entity, the Compliance Enforcement Authority conducts a Preliminary Screen pursuant to Section 3.8.

- The Spot Check team prepares a draft Spot Check report and provides the Registered Entity ten (10) business days to comment on the draft report.

- The Spot Check team considers any corrections based on the Registered Entity's comments, finalizes the Spot Check report and provides it to the Registered Entity and to NERC.

- If the Compliance Enforcement Authority is a Regional Entity, the Regional Entity provides the final report to NERC. NERC provides the report to FERC if the report pertains to a Registered Entity or to a portion of the Bulk Power System over which FERC has jurisdiction and/or to another Applicable Governmental Authority if the report pertains to a Registered Entity or to a portion of the Bulk Power System over which the other Applicable Governmental Authority has jurisdiction. The provision of the report to FERC or to another Applicable Governmental Authority shall be in accordance with Section 8.0, Reporting and Disclosure.

- The report will not be publicly posted, or otherwise made publicly available, by the Regional Entity or by NERC.

3.4 Compliance Investigations

A Compliance Investigation may be initiated at any time by the Compliance Enforcement Authority or NERC in response to a system disturbance, Complaint, or any potential noncompliance with a Reliability Standard identified by any other means.

Compliance Investigations will generally be led by the Regional Entity's staff. NERC reserves the right to assume the leadership of a Compliance Investigation.[1] The Regional Entity shall not be entitled to appeal NERC's decision to lead a Compliance Investigation.

Compliance Investigations are confidential, unless FERC directs that a Compliance Investigation should be public or that certain information obtained in the Compliance Investigation should be

[1]Examples of situations in which NERC may decide to lead a Compliance Investigation include: (i) to assure consistency in investigative processes, (ii) to coordinate Compliance Investigations into matters that may cross Regional Entity boundaries, (iii) where the potential noncompliance is related to the Regional Entity or one of its affiliates, divisions, committees or subordinate structures, or (iv) where the Regional Entity determines it cannot conduct the Compliance Investigation.

publicly disclosed. Confirmed Violations resulting from a Compliance Investigation will be made public.

FERC or another Applicable Governmental Authority may initiate an investigation at any time in response to a system disturbance, Complaint, or potential noncompliance with a Reliability Standard identified by any other means, or for any other purpose authorized by law. Investigations initiated by FERC or another Applicable Governmental Authority shall be governed by and conducted pursuant to the statutory authority and rules of the Applicable Governmental Authority and not the procedures set forth herein. If an Applicable Governmental Authority other than FERC initiates an investigation of a U.S.-related matter, NERC shall provide notice to FERC of the investigation prior to disclosure of any non-public U.S.-related compliance information regarding the matter to be investigated to the other Applicable Governmental Authority. NERC's notice to FERC shall identify the other Applicable Governmental Authority, shall describe the nature of the proposed disclosures to the other Applicable Governmental Authority, and shall state the procedures NERC will utilize in connection with the Compliance Investigation to ensure compliance with the requirements of 18 C.F.R. §39.7(b)(4) concerning nondisclosure of violations and Alleged Violations.

If FERC initiates an investigation of a non-U.S.-related matter, NERC shall provide notice of the investigation to the Applicable Governmental Authority having jurisdiction over the Registered Entity or the portion of the Bulk Power System that is the subject of the investigation prior to disclosure to FERC of any non-public non-U.S.-related compliance information regarding the matter to be investigated. NERC's notice to the other Applicable Governmental Authority shall describe the nature of the proposed disclosures to FERC and shall state the procedures NERC will utilize in connection with the investigation to ensure compliance with regulations of the other Applicable Governmental Authority or other law of the applicable jurisdiction concerning disclosure of non-public compliance information.

3.4.1 Compliance Investigation Process Steps

The process steps for a Compliance Investigation are as follows:

- The Compliance Enforcement Authority becomes aware of circumstances indicating a Reliability Standard may have been or is being violated and determines whether a Compliance Investigation is warranted. Within three (3) business days of the decision to initiate a Compliance Investigation, the Compliance Enforcement Authority: (i) notifies the Registered Entity of the initiation and initial scope of the Compliance Investigation, (ii) instructs the Registered Entity to preserve all records and information relevant to the Compliance Investigation, and (iii) provides a copy of the notice to NERC. The Compliance Investigation may be expanded beyond the initial scope based on information obtained by the Compliance Enforcement Authority after initiation of the Compliance Investigation.

- NERC assigns a NERC staff member to the Compliance Investigation as an observer or team member and to serve as a single point of contact for communications with NERC, and notifies the Registered Entity as to whether the NERC staff member is acting as an observer or as a team member. Within three (3) business days after NERC receives notice of the decision to initiate a Compliance Investigation, NERC will notify FERC and

each other Applicable Governmental Authority having jurisdiction over a Registered Entity or a portion of the Bulk Power System to which the Compliance Investigation relates. Any such notice to FERC or to another Applicable Governmental Authority will be provided in accordance with Section 8.0, Reporting and Disclosure.

The Compliance Enforcement Authority requests data or documentation and provides a list of individuals on the Compliance Investigation team and their recent employment history. Within ten (10) business days of receiving the notification of a Compliance Investigation, a Registered Entity subject to a Compliance Investigation may object to any individual member of the Compliance Investigation team on grounds of a conflict of interest or the existence of other circumstances that could interfere with the team member's impartial performance of his or her duties; however, the Registered Entity may not object to participation by NERC, by FERC staff or by staff of another Applicable Governmental Authority having reliability jurisdiction over the Registered Entity in the Compliance Investigation. Such objections must be provided in writing to the Compliance Enforcement Authority within such ten (10) business day period. The Compliance Enforcement Authority will make a final determination as to whether the individual will participate in the Compliance Investigation of the Registered Entity.

- The Registered Entity provides the required information to the Compliance Enforcement Authority in the format and by the Required Date as specified in the request. If information is not received in the time and format requested, the Compliance Enforcement Authority may initiate the steps in **Process for Non-Submittal of Requested Data in Attachment 1.**

- If necessary, the Compliance Investigation may include an on-site visit with interviews of the appropriate personnel and review of data.

- The Compliance Enforcement Authority may require the Registered Entity to (i) provide a verification under oath by an officer, employee, attorney or other authorized representative of the Registered Entity attesting to the accuracy, completeness and truth of the Registered Entity's responses to the Compliance Enforcement Authority's requests for information; and (ii) produce one or more officers, employees or other authorized representatives of the Registered Entity who are familiar with the matter(s) that are the subject of the Compliance Investigation, to be interviewed or to provide testimony under oath concerning such matters. The Compliance Enforcement Authority shall determine in each case (i) whether representatives of the Registered Entity shall be allowed to be present when an interview is taking place or testimony is being taken, and (ii) whether, and by what method, the interview or testimony shall be recorded; provided, that counsel for the person being interviewed or giving testimony may be present when the interview is being conducted or testimony is being taken (regardless of whether such counsel also represents the Registered Entity).

- The Compliance Enforcement Authority reviews information to determine compliance with the Reliability Standards. The Compliance Enforcement Authority may request additional data and/or information, if necessary.

- The Compliance Enforcement Authority completes the assessment of compliance with the Reliability Standard, which may include review of a Mitigation Plan or Mitigating Activities, and provides a report of the Compliance Investigation to NERC and the Registered Entity.

- If the Compliance Enforcement Authority, at any time during the Compliance Investigation, identifies a potential noncompliance with a Reliability Standard Requirement by a Registered Entity, the Compliance Enforcement Authority shall conduct a Preliminary Screen of the potential noncompliance in accordance with Section 3.8.

- If the Compliance Enforcement Authority determines that no violation occurred, it shall send the Registered Entity and NERC a notice that the Compliance Investigation has been completed. NERC will in turn notify FERC and, if the Compliance Investigation pertained to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, will also notify such other Applicable Governmental Authority. Any such notice to FERC or to another Applicable Governmental Authority shall be provided in accordance with Section 8.0, Reporting and Disclosure.

3.5 Self-Reports

Self-Reports are encouraged at the time a Registered Entity becomes aware (i) that it has, or may have, violated a Reliability Standard, or (ii) the Violation Severity Level of a previously reported violation has changed. Self-Reports of a violation of a Reliability Standard are encouraged regardless of whether the Reliability Standard requires reporting on a pre-defined schedule in the Compliance Program or whether the violation is determined outside the pre-defined reporting schedule. If possible, and without delaying the Self-Report, a Self-Report may include the actions that have been taken or will be taken to resolve the violation.

3.5.1 Self-Report Process Steps

The process steps for Self-Reports are as follows:

- The Compliance Enforcement Authority posts the Self-Report submittal forms and ensures they are maintained and available.

- The Registered Entity provides the Self-Report information to the Compliance Enforcement Authority.

- The Compliance Enforcement Authority reviews the information to evaluate compliance with the Reliability Standards and may request that the Registered Entity provide clarification or additional data and/or information.

- The Compliance Enforcement Authority conducts a Preliminary Screen of the Self-Report information in accordance with Section 3.8.

3.5A Self-Logging

Registered Entities found by the Compliance Enforcement Authority to be eligible, after a formal review of internal controls, pursuant to procedures adopted by NERC and the Regional Entities and provided to Applicable Governmental Authorities, may be granted approval by the Compliance Enforcement Authority to log noncompliance for subsequent review in lieu of submitting a Self-Report. The log shall be limited to noncompliance posing a minimal risk to the reliability of the Bulk Power System unless otherwise authorized by an Applicable Governmental Authority. Approved Registered Entities shall maintain a log with a detailed description of the noncompliance, the risk assessment, and the mitigating activities completed or to be completed. There is a rebuttable presumption that noncompliance logged in this manner will be resolved as a Compliance Exception. The Compliance Enforcement Authority will review the logs at least every three (3) months, with the possibility of extending the review period to six (6) months, and will make the logs available for review, upon request, by NERC and Applicable Governmental Authorities.

3.6 Periodic Data Submittals

The Compliance Enforcement Authority requires Periodic Data Submittals in accordance with the schedule stated in the applicable Reliability Standard, or as established by the Compliance Enforcement Authority, or on an as-needed basis. The Compliance Enforcement Authority shall issue requests for Periodic Data Submittals to Registered Entities within at least the minimum advance notice period specified by the applicable Reliability Standard. If the Reliability Standard does not specify an advance notice period, the Compliance Enforcement Authority will normally issue this request with no less than twenty (20) days advance notice.

3.6.1 Periodic Data Submittals Process Steps

The process steps for Periodic Data Submittal are as follows:

- The Compliance Enforcement Authority posts the current data reporting schedule on its website and informs Registered Entities of changes and/or updates. The Compliance Enforcement Authority ensures that the required submittal forms for the Reliability Standards being evaluated are maintained and available.

- The Compliance Enforcement Authority makes a request for a Periodic Data Submittal.

- The Registered Entity provides the required information to the Compliance Enforcement Authority in the format and by the Required Date specified in the request.

- The Compliance Enforcement Authority reviews the data submittal to determine compliance with the Reliability Standards and may request additional data and/or information if necessary.

- If the Compliance Enforcement Authority's review of the data submittal indicates a potential noncompliance with a Reliability Standard Requirement by the Registered Entity, the Compliance Enforcement Authority performs a Preliminary Screen of the potential noncompliance in accordance with Section 3.8.

Receipt of a Periodic Data Submittal by the Compliance Enforcement Authority shall not be construed as a finding by the Compliance Enforcement Authority that the Registered Entity is compliant with, not compliant with, subject to, or not subject to, the Reliability Standard Requirement.

3.7 Complaints

Either NERC or Regional Entities may receive Complaints alleging violations of a Reliability Standard. The Compliance Enforcement Authority will conduct a review of each Complaint it receives to determine if the Complaint provides sufficient basis for initiating another compliance monitoring or enforcement process, except that NERC will review any Complaint where the Compliance Enforcement Authority determines it cannot conduct the review, or if the complainant wishes to remain anonymous or specifically requests NERC to conduct the review of the Complaint.

If the Complaint is submitted to NERC, NERC will forward the information to the Regional Entity, as appropriate.

All anonymous Complaints will be reviewed and any resulting compliance monitoring or enforcement processes conducted by NERC will be conducted in accordance with Section 3.7.2 to prevent disclosure of the identity of the complainant.

The Compliance Enforcement Authority conducting the review will determine if the Complaint may be closed as a result of the initial review and assessment or if it provides sufficient basis for initiating another compliance monitoring or enforcement process. The Compliance Enforcement Authority will report the results of its review of the Complaint to NERC. If, as a result of the initial review of the Complaint, the Compliance Enforcement Authority determines that initiating another compliance monitoring or enforcement process is warranted, the Compliance Enforcement Authority shall conduct that compliance monitoring or enforcement process in accordance with the applicable provisions of Section 3.0.

3.7.1 Complaint Process Steps

The detailed process steps for the Complaint process are as follows:

- The complainant notifies NERC or a Regional Entity using the NERC compliance hotline, submitting a NERC Complaint reporting form, or by other means. NERC and the Regional Entity shall post a link to the Complaint reporting form on their respective websites. The Complaint should include sufficient information to enable NERC or the Regional Entity to make an assessment regarding whether the initiation of another compliance monitoring or enforcement process is warranted. NERC or the Regional Entity may not act on a Complaint if the Complaint is incomplete and does not include sufficient information.

- If the Compliance Enforcement Authority determines that initiation of another compliance monitoring or enforcement process is warranted, it initiates the compliance monitoring or enforcement process in accordance with the applicable provisions of Section 3.0 or Section 5.0; otherwise it takes no further action. The Compliance

Enforcement Authority notifies the complainant, the Registered Entity, and NERC of the initiation of the compliance monitoring or enforcement process. If the Compliance Enforcement Authority determines that initiation of another compliance monitoring or enforcement process is not warranted, it will notify the complainant, NERC, and the Registered Entity that no further action will be taken.

- The Compliance Enforcement Authority fully documents the Complaint and the Complaint review, and whether another compliance monitoring or enforcement process is warranted.

3.7.2 Anonymous Complainant Notification Procedure

A complainant who believes, or has information indicating, there has been a violation of a Reliability Standard, and wishes to remain anonymous, can report the information and request that the complainant's identity not be disclosed.[2] All Complaints lodged by a person or entity requesting that the complainant's identity not be disclosed shall be investigated by NERC following the procedural steps described in Section 3.7.1. Anonymous Complaints received by a Regional Entity will either be directed to NERC or the Regional Entity will collect and forward the information to NERC, at the Regional Entity's discretion. Neither NERC nor the Regional Entity shall disclose the identity of any person or entity reporting information indicating violations of Reliability Standards to NERC or to a Regional Entity that requests that his/her/its identity not be revealed. The identity of the complainant will only be known by NERC and in the case where a Regional Entity collects the information, by NERC and the Regional Entity. If the Compliance Enforcement Authority determines that initiation of another compliance monitoring and enforcement process is not warranted, it will notify the complainant, NERC, and the Registered Entity that no further action will be taken.

3.8 Preliminary Screen

If the Compliance Enforcement Authority obtains information, through one of the compliance monitoring processes described in this Section 3.0 or by any other means, that indicates a potential noncompliance with a Reliability Standard Requirement, the Compliance Enforcement Authority shall conduct a Preliminary Screen of the potential noncompliance. The Preliminary Screen shall be conducted within five (5) business days after the Compliance Enforcement Authority identifies the potential noncompliance, except that (i) if the Compliance Enforcement Authority identifies the potential noncompliance during a Compliance Audit, the Preliminary Screen shall be conducted immediately following the exit briefing of the Registered Entity, and (ii) if the Compliance Enforcement Authority identifies the potential noncompliance during a Compliance Investigation, the Preliminary Screen shall be conducted immediately after the Registered Entity is first notified of the potential noncompliance identified by the Compliance Investigation.

A Preliminary Screen shall be limited to determining whether:

[2]NERC has established a Compliance Hotline that may be used for the submission of Complaints by persons or entities that do not want his/her/its identity disclosed (see www.nerc.com for additional information).

(1) the entity allegedly involved in the potential noncompliance is a Registered Entity;

(2) the Reliability Standard Requirement to which the evidence of potential noncompliance relates is applicable to the entity, has been approved by the Applicable Governmental Authority, and is in effect at the time of the potential noncompliance; and

(3) if known, the potential noncompliance is not a duplicate of a Possible Violation or Alleged Violation that is currently being processed.

If the Preliminary Screen results in an affirmative determination with respect to the above criteria, a Possible Violation exists and the Compliance Enforcement Authority shall proceed in accordance with Section 5.0, unless the Compliance Exception Process is used in accordance with Section 3A.1.

The Compliance Enforcement authority shall maintain records of all Preliminary Screens.

3A.0 ENFORCEMENT DISCRETION

Not all instances of noncompliance with Reliability Standards require the same type of processing and documentation. Noncompliance that does not pose a serious or substantial risk to the reliability of the Bulk Power System may be resolved through streamlined processes, when appropriate, consistent with processes approved by NERC and Applicable Governmental Authorities.

Absolute adherence to the enforcement process set out in section 5.0 may not be the most appropriate, efficient, or desirable means by which to achieve the overall objectives of the Compliance Program for NERC, the Compliance Enforcement Authority, and the Registered Entity.

The Find, Fix, Track and Report and the Compliance Exception processes are alternatives to the process outlined in section 5.0.

3A.1 Compliance Exception Process

The Compliance Exception process may be used to address noncompliance posing a minimal risk to the reliability of the Bulk Power System, unless an Applicable Governmental Authority authorizes expansion of the program. Compliance Exceptions are not included in a Registered Entity's compliance history for penalty purposes. However, a Compliance Enforcement Authority must (a) consider a history of Compliance Exceptions where the failure to fully remediate the underlying compliance matter contributes to a subsequent serious or substantial noncompliance and (b) assess subsequent noncompliance to determine whether a Registered Entity should continue to qualify for Compliance Exception treatment.

The Compliance Exception process requires that:

(1) The Registered Entity mitigates the noncompliance; and

(2) The facts and circumstances of the noncompliance, including those associated with the determination of the level of risk and the related mitigation, are available for review by NERC and Applicable Governmental Authorities; and

(3) The noncompliance is tracked and analyzed as necessary and appropriate to identify emerging risks and other pertinent trends; and

(4) The Registered Entity is provided the opportunity to object to the use of the Compliance Exception Process to resolution of the noncompliance.

Changes to the processes and principles articulated in this section must be approved by Applicable Governmental Authorities.

4.0 ANNUAL IMPLEMENTATION PLANS

4.1 NERC Compliance Monitoring and Enforcement Program Implementation Plan

NERC will maintain and update the NERC Implementation Plan, to be carried out by Compliance Enforcement Authorities in the performance of their responsibilities and duties in implementing the NERC Compliance Monitoring and Enforcement Program. The NERC Implementation Plan will be provided to the Regional Entities on or about September 1 of each year and will identify risk elements related to the Reliability Standards to be considered for compliance oversight by the Compliance Enforcement Authority. The NERC Implementation Plan will be posted on the NERC website. NERC may update and revise the NERC Implementation Plan during the course of the year as necessary. Regional Entities have discretion to make modifications to the NERC Implementation Plan with respect to individual Registered Entities.

4.2 Regional Implementation Plan

By on or about October 1 of each year, each Regional Entity will submit a Regional Implementation Plan for the following calendar year to NERC for review and approval. The Regional Implementation Plan and the Regional Entity's other relevant Compliance Program documents shall be posted on the Regional Entity's website. The Regional Entity may update and revise the Regional Entity Implementation Plan during the course of the year as necessary, with NERC approval, or as required by NERC. Regional Entities have discretion to make modifications to the Regional Entity Implementation Plan with respect to individual Registered Entities.

5.0 ENFORCEMENT ACTIONS

The Compliance Enforcement Authority shall determine (i) whether there have been violations of Reliability Standards by Registered Entities within the Compliance Enforcement Authority's Area of Responsibility, and (ii) if so, the appropriate Mitigating Activities, and Penalties and sanctions, as prescribed in the NERC *Sanction Guidelines* (Appendix 4B to the NERC Rules of Procedure). NERC will work to achieve consistency in the application of the *Sanction*

Guidelines by Regional Entities by direct oversight and review of Penalties and sanctions, and each Regional Entity shall provide to NERC such information as is requested by NERC concerning any Penalty, sanction, or Mitigating Activities imposed by the Regional Entity.

The imposition and acceptance of Penalties and sanctions shall not be considered an acceptable alternative to any Registered Entity's continuing obligation to comply with the Reliability Standards.

The Compliance Enforcement Authority has authority to collect Documents, data and information in the manner it deems most appropriate, including requesting copies be made of Documents, data and information and removing those copies from the Registered Entity's location in accordance with appropriate security procedures conforming to Section 1500 of the Rules of Procedure and other safeguards as appropriate in the circumstances to maintain the confidential or other protected status of the Documents, data and information, such as information held by a governmental entity that is subject to an exemption from disclosure under the United States Freedom of Information Act, or a comparable state or provincial law, that would be lost of the information were placed into the public domain. Parties engaged in the process described in this section should consult with each other on the data and information that would be appropriate for effectively addressing this section's process requirements. If a Registered Entity believes that a request for Documents, data or information is unreasonable, the Registered Entity may request a written determination from the NERC general counsel. If Documents, data or information requested from a Registered Entity in connection with an enforcement process are not received by the Required Date, the Compliance Enforcement Authority may execute the steps described in **Attachment 1, Process for Non-submittal of Requested Data.**

The following enforcement process is undertaken by the Compliance Enforcement Authority following identification of a Possible Violation of a Reliability Standard Requirement by a Registered Entity. However, under the circumstances presented by some Possible Violations, Alleged Violations or Confirmed Violations, absolute adherence to the following enforcement process, to the exclusion of other approaches, may not be the most appropriate, efficient or desirable means by which to achieve the overall objectives of the Compliance Program for NERC, the Compliance Enforcement Authority and the Registered Entity. In such circumstances, other approaches may be considered and employed. The Registered Entity shall be entitled to object to the use of any such other approach.

5.1 Notice of Possible Violation

If a Preliminary Screen conducted in accordance with Section 3.8 results in an affirmative determination with respect to the Preliminary Screen criteria, a Possible Violation exists. Unless the Compliance Exception process in Section 3A.1 is used to address the Possible Violation, the Compliance Enforcement Authority shall issue a Notice of Possible Violation to the Registered Entity. The Notice of Possible Violation shall:

(i) state that a Possible Violation by the Registered Entity has been identified;

(ii) provide a brief description of the Possible Violation, including the Reliability Standard requirement(s) and, if known, the date(s) involved; and

(iii) instruct the Registered Entity to retain and preserve all data and records relating to the Possible Violation.

Upon issuing a Notice of Possible Violation or receiving information on a Compliance Exception (whether resulting from Self-Logging or not), the Compliance Enforcement Authority reports the Possible Violation to NERC. NERC reports the Possible Violation to the Board of Trustees Compliance Committee and submits a Notice of Possible Violation, or information on a Compliance Exception (whether resulting from Self-Logging or not), on a confidential basis, to FERC and to other Applicable Governmental Authorities, as applicable. Any such notice to FERC or to other Applicable Governmental Authorities shall be provided in accordance with Section 8.0, Reporting and Disclosure.

5.2 Assessment of Possible Violation

After issuing a Notice of Possible Violation, the Compliance Enforcement Authority shall conduct an assessment of the facts and circumstances surrounding the Possible Violation to determine whether evidence exists to indicate the Registered Entity has violated the Reliability Standard Requirement(s) identified in the Notice of Possible Violation, or whether the Possible Violation should be dismissed. The Compliance Enforcement Authority may consider any additional information to demonstrate that the Possible Violation should be dismissed or modified or resolved through the Find, Fix, Track and Report process in section 5.2A.

5.2A FFT Process

The Find, Fix, Track and Report process may be used to address noncompliance posing a minimal or moderate risk to the reliability of the Bulk Power System.

The FFT process requires that:

(1) The Registered Entity mitigates the noncompliance; and

(2) The facts and circumstances of the noncompliance, including those associated with the determination of the level of risk and the related mitigation, are available for review by NERC and Applicable Governmental Authorities; and

(3) FFTs are tracked and analyzed as necessary by NERC as appropriate to identify emerging risks and other pertinent trends; and

(4) The Registered Entity is provided the opportunity to object to the use of the FFT process to resolution of the noncompliance.

5.3 Notification to Registered Entity of Alleged Violation

If the Compliance Enforcement Authority determines, based on an assessment of the facts and circumstances surrounding a Possible Violation, that evidence exists to indicate a Registered Entity has violated a Reliability Standard, the Compliance Enforcement Authority shall notify the Registered Entity of the determination of the Alleged Violation, through issuance of a Notice of Alleged Violation and Proposed Penalty or Sanction or similar notification, and shall report the Alleged Violation to NERC. The notification of Alleged Violation shall be transmitted by

the Compliance Enforcement Authority to the Registered Entity by electronic mail and shall be effective as of the date of the electronic mail message from the Compliance Enforcement Authority transmitting the notification. The notification of Alleged Violation shall include, at a minimum:

(i) the Reliability Standard and Requirement(s) thereof the Registered Entity has allegedly violated,

(ii) the date and time the Alleged Violation occurred (or is occurring),

(iii) the facts the Compliance Enforcement Authority believes demonstrate or constitute the Alleged Violation,

(iv) the proposed Penalty or sanction, if any, determined by the Compliance Enforcement Authority to be applicable to the Alleged Violation in accordance with the NERC *Sanction Guidelines*, including an explanation of the basis on which the particular Penalty or sanction was determined to be applicable,

(v) notice that the Registered Entity shall, within thirty (30) days, elect one of the following options or the Compliance Enforcement Authority will deem the Registered Entity to have accepted the determination of violation and proposed Penalty or sanction:

1. agree with the Alleged Violation and proposed Penalty or sanction, and agree to submit and implement a Mitigation Plan or other Mitigating Activities to correct the violation and its underlying causes, and may provide a response in accordance with Section 5.4, or

2. agree with the Alleged Violation and agree to submit and implement a Mitigation Plan or other Mitigating Activities to eliminate the violation and its underlying causes, but contest the proposed Penalty or sanction, and may provide a response in accordance with Section 5.4, or

3. contest both the Alleged Violation and proposed Penalty or sanction,

(vi) notice that the Registered Entity may elect to submit a Mitigation Plan while contesting the Alleged Violation and/or the proposed Penalty or sanction, and that submission of a Mitigation Plan will not waive the Registered Entity's right to contest the Alleged Violation and/or the proposed Penalty or sanction;

(vii) notice that if the Registered Entity elects to contest the Alleged Violation and/or the proposed Penalty or sanction, the Registered Entity may elect to have a hearing conducted pursuant to either (i) the short-form procedure in Section 1.3.4, or (ii) the general hearing procedure, in **Attachment 2, Hearing Procedures**, and

(viii) required procedures to submit the Registered Entity's Mitigation Plan.

NERC shall notify FERC of the Alleged Violation and, if the Alleged Violation pertains to a Registered Entity or to a portion of the Bulk Power System over which another Applicable

Governmental Authority has jurisdiction, shall notify such other Applicable Governmental Authority of the Alleged Violation, within two (2) business days of receipt from the Compliance Enforcement Authority. Any such notice to FERC or to another Applicable Governmental Authority shall be provided in accordance with Section 8.0, Reporting and Disclosure.

5.4 Registered Entity Response

If the Registered Entity agrees with, does not contest, or does not respond to the notification of Alleged Violation within thirty (30) days following the date of the notification of Alleged Violation by electronic mail, it shall be deemed to have accepted the Compliance Enforcement Authority's determination of violation and Penalty or sanction, and the Compliance Enforcement Authority shall issue a Notice of Confirmed Violation or similar notification to the Registered Entity and shall report the Confirmed Violation to NERC. At the time of notifying the Registered Entity of the Confirmed Violation, the Compliance Enforcement Authority shall also provide notice to the Registered Entity that it may provide a written explanatory statement to accompany the filing with FERC and public posting of the Confirmed Violation. The Registered Entity's statement must include the name, title, and signature of an officer, employee, attorney or other authorized representative of the Registered Entity.

If the Registered Entity contests the Alleged Violation or the proposed Penalty or sanction, the Registered Entity shall submit to the Compliance Enforcement Authority, within thirty (30) days following the date of the notification of the Alleged Violation, a response explaining its position, signed by an officer, employee, attorney or other authorized representative together with any supporting information and documents. The Compliance Enforcement Authority shall schedule a conference with the Registered Entity within ten (10) business days after receipt of the response. If the Compliance Enforcement Authority and the Registered Entity are unable to resolve all issues within forty (40) days after the Registered Entity's response, the Registered Entity may request a hearing. The Compliance Enforcement Authority and the Registered Entity may agree in writing to extend the forty (40) day period. If no hearing request is made prior to the end of the forty (40) day period, the violation will be become a Confirmed Violation.

If a hearing is requested the Compliance Enforcement Authority shall initiate the hearing process in accordance with **Attachment 2, Hearing Procedures**.

5.5 Hearing Process for Compliance Hearings

The Compliance Enforcement Authority hearing process is set forth in **Attachment 2**.

5.6 Settlement Process

The Registered Entity can request settlement negotiations at any time, including prior to the issuance of notification of an Alleged Violation; however, the Compliance Enforcement Authority may decline to engage in or to continue settlement negotiations after a Possible Violation or Alleged Violation becomes a Confirmed Violation in accordance with Section 5.4. The Registered Entity or the Compliance Enforcement Authority may terminate settlement negotiations at any time. Where the Compliance Enforcement Authority has agreed top engage in settlement negotiations, the running of the time period specified in Section 5.4 for the Registered Entity to respond to the notification of Alleged Violation is suspended until

settlement negotiations are concluded or terminate. NERC shall be notified of all settlement negotiations and may participate in any settlement negotiations. All settlement negotiations will be confidential until such time as the settlement is approved by NERC. For all settlement discussions, the Compliance Enforcement Authority shall require the Registered Entity to designate an individual(s) authorized to negotiate on its behalf.

The Compliance Enforcement Authority may consider all relevant facts in settlement negotiations. A settlement agreement must ensure that the reliability of the Bulk Power System will not be compromised by the settlement and that a violation of a Reliability Standard will not occur as a result of the settlement. All settlement agreements must provide, if the settlement is approved, for waiver of the Registered Entity's right to further hearings and appeal.

The Compliance Enforcement Authority and the Registered Entity will execute a settlement agreement setting forth the final settlement terms including all Penalties, sanctions and mitigation requirements provided for in the final settlement.

The Compliance Enforcement Authority shall report the terms of all settlements of compliance matters to NERC. NERC will review the settlement for the purpose of evaluating its consistency with other settlements entered into for similar violations or under other, similar circumstances. The Registered Entity may submit an explanatory statement, conforming to the requirements of Section 5.4, to be included in the settlement agreement and which shall be subject to consent of the Compliance Enforcement Authority as part of the settlement agreement. The settlement agreement may state that the Registered Entity (i) admits the Alleged Violation, or (ii) does not contest the Alleged Violation, or (iii) neither admits nor denies the Alleged Violation, but may not state that the Registered Entity denies the Alleged Violation. Based on this review, NERC will either approve the settlement or reject the settlement and notify the Compliance Enforcement Authority of any changes to the settlement that would result in approval, and within five (5) business days the Compliance Enforcement Authority will in turn notify the Registered Entity. If NERC rejects the settlement, the Compliance Enforcement Authority will attempt to negotiate a revised settlement agreement with the Registered Entity including any changes to the settlement specified by NERC.

NERC will report the approved settlement of the violation to FERC and, if the settlement relates to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, to such other Applicable Governmental Authority. Any such report shall be provided in accordance with Section 8.0, Reporting and Disclosure. NERC will also publicly post the violation settled (regardless of whether the settlement includes or does not include an admission of a violation) and the resulting Penalty or sanction provided for in the settlement. This posting shall include a copy of the settlement or a description of the terms of the settlement, and a copy of any Mitigation Plan that is agreed to as part of the settlement, with any Critical Energy Infrastructure Information and Confidential Information redacted. The Compliance Enforcement Authority will issue a letter setting forth the final settlement terms including all Penalties, sanctions and mitigation requirements provided for in the final settlement. Postings of Notices of Confirmed Violations are addressed in Section 8.0.

5.7 NERC Appeal Process

A Registered Entity or the Compliance Enforcement Authority may appear the decision of a ~~Regional Entity~~ Hearing Body to NERC, as provided for in NERC Rules of Procedure, Section 409.

On appeal, NERC shall either affirm the decision or remand to the Compliance Enforcement Authority with reasons for its remand, which may include a direction to the Compliance Enforcement Authority to revise the decision. If NERC affirms the decision, the Compliance Enforcement Authority shall issue a Notice of Confirmed Violation to the Registered Entity. If NERC directs the Compliance Enforcement Authority to revise the decision, a Registered Entity that was the subject of the decision or the Compliance Enforcement Authority may reopen the proceeding on any issue whose resolution is affected by NERC's directive, irrespective of whether the issue was previously litigated, settled or unopposed.

5.8 Notification of Confirmed Violation

A Notice or other notification of Confirmed Violation issued to a Registered Entity pursuant to Sections 5.4 or 5.7 shall include a detailed record of the enforcement action, including the facts and circumstances analyzed and the information on which the Compliance Enforcement Authority relied in proposing a Penalty or sanction.

After NERC receives a notification of Confirmed Violation from the Compliance Enforcement Authority, NERC shall review the notification of Confirmed Violation and utilize the information therein to prepare a Notice of Penalty. NERC shall advise the Compliance Enforcement Authority of any additional detail or further development of the factual findings that NERC deems necessary before the Notice of Penalty can be issued.

NERC may direct the Compliance Enforcement Authority to revise a Penalty determination, in which case the Registered Entity subject to the Penalty, or the Compliance Enforcement Authority, as applicable, may reopen the proceedings on any issue on which the Penalty was based, irrespective of whether the issue was previously litigated, settled or unopposed.

5.9 Notice of Penalty

If (i) the Registered Entity accepts the Notice of Alleged Violation and Proposed Penalty or Sanction or other notification of enforcement action from the Compliance Enforcement Authority, or (ii) a decision has been entered affirming an Alleged Violation and all appeals have been concluded, or (iii) a settlement agreement has been reached addressing the Possible Violation or Alleged Violation, NERC shall submit a Notice of Penalty to the Applicable Governmental Authority and provide a copy to the Compliance Enforcement Authority. The Compliance Enforcement Authority shall inform the Registered Entity that a Notice of Penalty is pending public filing, at least five (5) business days prior to the public filing and posting. NERC will file the Notice of Penalty with FERC and any other Applicable Governmental Authority no sooner than five (5) business days after NERC approves the Notice of Confirmed Violation or settlement agreement.

NERC shall file the Notice of Penalty with FERC and, if the Possible Violation or Alleged Violation pertains to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, to such other Applicable

Governmental Authority. Any such filing with FERC or with another Applicable Governmental Authority shall be made in accordance with Section 8.0, Reporting and Disclosure. NERC will include with the Notice of Penalty any statement provided by the Registered Entity as set forth in Sections 5.4 or 5.6.

The Penalty or sanction will be effective upon expiration of the thirty (30) day period following filing with FERC of the Notice of Penalty (or such longer period as ordered by FERC) or, if FERC decides to review the Penalty or sanction, upon final determination by FERC.

5.10 Completion of Enforcement Action

Following FERC approval of, or expiration of the period for action by FERC on, a Notice of Penalty filed by NERC, the Compliance Enforcement Authority shall issue a payment due notice and invoice to the Registered Entity. The payment due notice and invoice shall state the payment due date which shall be thirty (30) days from the date of the payment due notice and invoice. Upon payment of all monetary Penalties by the Registered Entity, the Compliance Enforcement Authority shall issue a notice confirming payment to the Registered Entity, and provide a copy of the notice confirming payment to NERC. Following the completion by the Registered Entity of all requirements set forth in the Notice of Penalty and any settlement agreement, the Compliance Enforcement Authority shall issue the Registered Entity a Notice of Completion of Enforcement Action.

If the Compliance Enforcement Authority dismisses or disposes of a Possible Violation or Alleged Violation that does not become a Confirmed Violation, the Compliance Enforcement Authority shall issue a Notice of Completion of Enforcement Action to the Registered Entity.

A copy of the Notice of Completion of Enforcement Action shall also be provided to NERC by the Compliance Enforcement Authority.

The Notice of Completion of Enforcement Action shall include a release of any data retention directives that were previously issued to the Registered Entity in connection with the matter. Upon issuance of a Notice of Completion of Enforcement Action, tracking of the violation is completed, and the enforcement action shall be closed.

5.11 Special Procedures for an Enforcement Action Against an ISO/RTO Where the Monetary Penalty May be Allocated by the ISO/RTO to Other Entities

A Registered Entity that is an ISO/RTO may have authority to allocate, pursuant to a proceeding under section 205 of the Federal Power Act, some or all of a monetary Penalty imposed on the ISO/RTO for violation of a Reliability Standard, to another entity(ies) that the Compliance Enforcement Authority, NERC or FERC determines was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation of the Reliability Standard. This section sets forth the procedures to be followed when an ISO/RTO that has received a Notice of Possible Violation requests a determination by the Compliance Enforcement Authority that another entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation (if confirmed) identified in the Notice of Possible Violation.

The procedures in this section apply only where an ISO/RTO requests a determination that a specified other entity(ies) was responsible, in whole or in part, for actions or omissions that

caused or contributed to the violation (if confirmed) identified in a Notice of Possible Violation issued to the ISO/RTO, and shall not apply where the ISO/RTO anticipates or is entitled to allocate or assign a monetary Penalty among all, or an identified segment of, its members, customers or users, pursuant to general cost recovery provisions in the ISO/RTO's tariffs, agreements or governance documents and regardless of actual fault or responsibility of the entities to whom the monetary Penalty is issued for the violation.

5.11.1 ISO/RTO's Request for Determination and Notice to Other Entity(ies)

In order to request the Compliance Enforcement Authority to make a determination in an enforcement action that a specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to a violation (if confirmed) of a Reliability Standard for which the ISO/RTO has received a Notice of Possible Violation, the ISO/RTO shall, no later than ten (10) business days after receiving the Notice of Possible Violation or such additional period as the Compliance Enforcement Authority may permit for good cause shown (i) submit a written request to the Compliance Enforcement Authority and (ii) issue a notice to the specified other entity(ies), each conforming to the requirements of the following two paragraphs of this section.

The ISO/RTO's written request to the Compliance Enforcement Authority shall contain:

(1) the Compliance Enforcement Authority's identification number for the Notice of Possible Violation;

(2) a statement that the ISO/RTO is requesting that the Compliance Enforcement Authority make a determination that a specified other entity(ies) was responsible, in whole or in part, for actions and omissions that caused or contributed to the violation (if confirmed) identified in the Notice of Possible Violation;

(3) the name(s) of, and contact information for, the specified other entity(ies), including name(s) and address(es) of the entity(ies) and name(s), telephone number(s) and e-mail address(es) of the contact person(s) for the other entity(ies);

(4) a statement that the ISO/RTO has authority to allocate some or all of the monetary Penalty to the specified other entity(ies), including citations to any supporting tariffs, agreements, orders, or governance documents, and a brief explanation to show that the specified other entity(ies) are subject to the tariffs, agreements, orders and/or other governance documents; and

(5) a brief statement of the factual basis on which the ISO/RTO contends in good faith that the specified other entity(ies) was responsible for actions or omissions that caused or contributed to the violation (if confirmed) identified in the Notice of Possible Violation. As the enforcement action proceeds, the ISO/RTO may supplement, expand or modify this explanation as additional information becomes available during the course of the enforcement action.

The ISO/RTO's notice to the specified other entity(ies) shall contain the following information:

(1) The name of the specified other entity, and the name, telephone number and e-mail address of the specified other entity's contact person (person to whom the notice is being sent);

(2) A statement that the ISO/RTO has received a Notice of Possible Violation from the Compliance Enforcement Authority, the Compliance Enforcement Authority's identification number for the Notice of Possible Violation, and contact information for the Compliance Enforcement Authority;

(3) A statement that the ISO/RTO has requested the Compliance Enforcement Authority to determine that the specified other entity was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation identified in the Notice of Possible Violation, and that the ISO/RTO intends to seek to allocate to the specified other entity all or a portion of any monetary Penalty that is imposed on the ISO/RTO for the violation (if confirmed), if the Compliance Enforcement Authority determines the specified other entity was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation identified in the Notice of Possible Violation.

(4) A statement that the specified other entity should promptly contact the Compliance Enforcement Authority for further information and to request to participate in the enforcement action relating to the Notice of Possible Violation.

The ISO/RTO shall cause its notice to the specified other entity(ies) to be delivered to the other entity(ies) by next-business-day delivery using a delivery service that provides verification of delivery. The ISO/RTO shall provide the Compliance Enforcement Authority with (i) a copy of the notice sent to each specified other entity, and (ii) a copy of the delivery service's verification of delivery of the notice to each specified other entity.

5.11.2 Responses of the Compliance Enforcement Authority and the Specified Other Entity(ies) to ISO/RTO's Request for Determination and Notice

If (i) the ISO/RTO's written request meets the requirements of Section 5.11.1, the Compliance Enforcement Authority shall provide the specified other entity(ies) with a copy of a non-disclosure agreement (which shall include the specified other entity's agreement to comply with the confidentiality requirements of the Compliance Program and of Section 1500 of the NERC Rules of Procedure) that must be executed to obtain a copy of the Notice of Possible Violation and a copy of the ISO/RTO's written request to the Compliance Enforcement Authority for a determination that the specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation (if confirmed) identified in the Notice of Possible Violation. In addition, the Compliance Enforcement Authority shall advise the specified other entity(ies) that: (i) the specified other entity(ies) may elect not to participate in the enforcement action, and may submit a written statement to the Compliance Enforcement Authority stating why the specified other entity is not participating and providing any facts or

information the other entity wishes to provide concerning the occurrence(s) that are the subject of the Notice of Possible Violation, and (ii) whether or not the specified other entity elects to participate in the enforcement action, the Compliance Enforcement Authority may determine that the specified other entity was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation identified in the Notice of Possible Violation.

If the ISO/RTO's written request meets the requirements of Section 5.11.1, then the specified other entity(ies) shall be permitted to participate in the enforcement action concerning the Notice of Possible Violation if the other entity(ies) submits a written request to participate to the Compliance Enforcement Authority and executes a non-disclosure agreement in the form provided by the Compliance Enforcement Authority. The specified other entity must submit its written request to participate prior to, as applicable (i) the date of execution of a settlement agreement between the Compliance Enforcement Authority and the ISO/RTO, or (ii) the date that the Compliance Enforcement Authority issues a Notice of Confirmed Violation to the ISO/RTO. The Compliance Enforcement Authority is not required to suspend or delay the enforcement process pending receipt of a request to participate from the specified other entity(ies), nor to revisit or redo any aspect of the enforcement process that has already occurred prior to receipt of the specified other entity(ies)'s written request to participate; however, upon receipt of a written request to participate and executed nondisclosure agreement from the specified other entity(ies), the Compliance Enforcement Authority shall suspend activity in the enforcement action until it has acted on the request to participate.

Upon receiving the specified other entity's written request to participate in the enforcement action and the other entity's executed nondisclosure agreement, the Compliance Enforcement Authority shall issue a notice to the ISO/RTO and to the specified other entity stating that the specified other entity is allowed to participate in the enforcement action. The Compliance Enforcement Authority's notice that the specified other entity is allowed to participate in the enforcement action shall include a copy of the Notice of Possible Violation originally issued to the ISO/RTO and, if a Notice of Alleged Violation and Proposed Penalty or Sanction or similar notification has been issued to the ISO/RTO, a copy of the latter Notice or notification. Upon receiving notice from the Compliance Enforcement Authority that it is allowed to participate in the enforcement action, the specified other entity may participate in the same manner as the ISO/RTO and shall be subject to all applicable requirements and deadlines specified in the NERC Compliance Program.

If the ISO/RO fails to meet the requirements of Section 5.11.1, the Compliance Enforcement Authority shall issue a notice to the ISO/RTO and to the specified other entity(ies) stating that the Compliance Enforcement Authority will not make the determination requested by the ISO/RTO and therefore the specified other entity will not be allowed to participate in the enforcement action relating to the Notice of Possible Violation.

5.11.3 Compliance Enforcement Authority's Notices to NERC

(a) Within five (5) business days after receiving an ISO/RTO's written request for a determination that a specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to a violation identified in the Notice of Possible Violation issued to the ISO/RTO, the Compliance Enforcement Authority shall provide to NERC (i) a copy

of the ISO/RTO's written request for a determination that a specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation identified in the Notice of Possible Violation, and (ii) the ISO/RTO's notice to the specified other entity(ies).

(b) On the same day that the Compliance Enforcement Authority issues a notice pursuant to Section 5.11.2 stating, as applicable, that (i) it will or will not make the determination requested by the ISO/RTO or (ii) the specified other entity(ies) are or are not allowed to participate in the enforcement action, the Compliance Enforcement Authority shall provide a copy of the notice to NERC and shall send a copy of the notice to any other entities that have been allowed to participate in the enforcement action.

5.11.4 Compliance Enforcement Authority's Determination

After issuing a notice pursuant to Section 5.11.3 that it will make a determination as to whether the specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation that is the subject of the Notice of Possible Violation issued to the ISO/RTO, then, if the enforcement action is not resolved by a settlement agreement stating whether or not the specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation identified in the Notice of Possible Violation, the Compliance Enforcement Authority shall make, and include in its proposed Notice of Penalty, its determination of whether or not the specified other entity(ies) were responsible, in whole or in part, for actions or omissions that caused or contributed to the violation. The Compliance Enforcement Authority's determination shall only address whether or not the specified other entity(ies) was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation, and shall not address whether all or a part of any monetary Penalty imposed on the ISO/RTO for the violation should be allocated or assigned to the specified other entity(ies).

The specified other entity(ies) shall be entitled to request a hearing on the Compliance Enforcement Authority's determination pursuant to Section 1.3.1 of Attachment 2 of this Appendix 4C, and to appeal the Hearing Body's decision pursuant to Section 1.7.10 of Attachment 2 to this Appendix 4C, as though the specified other entity(ies) were a Registered Entity(ies).

5.11.5 Procedure Where ISO/RTO Members Are Allowed to Directly Assign Monetary Penalties for Violations of Reliability Standards to the ISO/RTO

If an ISO/RTO's tariffs, agreement or other relevant governance documents establish procedures that allow members of the ISO/RTO to directly assign to the ISO/RTO monetary Penalties imposed on the ISO/RTO member(s) for violations of Reliability Standards, then the ISO/RTO members may follow the same requirements of Sections 5.11.1 and 511.2 as are applicable to an ISO/RTO under those sections, and the ISO/RTO shall be afforded the same rights to participate in the enforcement action as a specified other entity under Sections 5.11.1, 5.11.2, and 5.11.4, subject to the same requirements and conditions specified in those sections. In such

circumstances, the ISO/RTO shall be deemed to be a "specified other entity" for purposes of this Section.

5.11.6 Obligation to Pay Monetary Penalty

(a) The ISO/RTO shall be obligated and responsible to pay any monetary Penalty imposed by the Compliance Enforcement Authority on the ISO/RTO for violation of a Reliability Standard, in accordance with Section 5.10, (i) regardless of whether the Compliance Enforcement Authority has made a determination that a specified other entity was responsible, in whole or in part, for actions or omissions that caused or contributed to the violation, (ii) without regard to the timing of any separate proceeding(s) in which the ISO/RTO seeks to allocate some or all of the monetary Penalty to a specified other entity(ies), and (iii) without regard to whether or when the ISO/RTO receives payment from the specified other entity(ies).

(b) In an enforcement action subject to Section 5.11.5, the ISO/RTO member(s) shall be obligated and responsible to pay any monetary Penalty imposed by the Compliance Enforcement Authority on the ISO/RTO member(s) for violation of a Reliability Standard, regardless of whether or when the ISO/RTO members receive payment or reimbursement from the ISO/RTO.

6.0 MITIGATION OF VIOLATIONS OF RELIABILITY STANDARDS

The Compliance Enforcement Authority has authority to collect Documents, data and information in the manner it deems most appropriate, including requesting copies be made of Documents, data and information and removing those copies from the Registered Entity's location in accordance with appropriate security procedures conforming to Section 1500 of the Rules of Procedure and other safeguards as appropriate in the circumstances to maintain the confidential or other protected status of the Documents, data and information, such as information held by a governmental entity that is subject to an exemption from disclosure under the United States Freedom of Information Act, or a comparable state or provincial law, that would be lost of the information were placed into the public domain. Parties engaged in the process described in this section should consult with each other on the data and information that would be appropriate for effectively addressing this section's process requirements. If a Registered Entity believes that a request for Documents, data or information is unreasonable, the Registered Entity may request a written determination from the NERC general counsel. If Documents, data, information or other reports requested from a Registered Entity in connection with development of a Mitigation Plan or other Mitigating Activities are not received by the Required Date, the Compliance Enforcement Authority may execute the steps described in **Attachment 1, Process for Non-submittal of Requested Data.**

6.1 Requirement for Submission of Mitigation Plans

A Registered Entity found to be in violation of a Reliability Standard shall file with the Compliance Enforcement Authority (i) a proposed Mitigation Plan to correct the violation, or (ii) a description of how the violation has been mitigated, and any requests for extensions of Mitigation Plans or a report of completed mitigation. A Registered Entity may also submit a proposed Mitigation Plan at any other time, including with a Self-Report, or, without admitting it

has committed a violation, in response to a Notice of Possible Violation or notification of Alleged Violation.

6.2 Contents of Mitigation Plans

A Mitigation Plan shall include the following information:

- The Registered Entity's point of contact for the Mitigation Plan, who shall be a person (i) responsible for filing the Mitigation Plan, (ii) technically knowledgeable regarding the Mitigation Plan, and (iii) authorized and competent to respond to questions regarding the status of the Mitigation Plan. This person may be the Registered Entity's point of contact described in Section 2.0.

- The Possible, Alleged or Confirmed Violation(s) of Reliability Standard(s) the Mitigation Plan will correct.

- The cause of the Possible, Alleged or Confirmed Violation(s).

- The Registered Entity's action plan to correct the Possible, Alleged or Confirmed Violation(s).

- The Registered Entity's action plan to correct the cause of the Possible, Alleged or Confirmed Violation.

- The Registered Entity's action plan to prevent recurrence of the Possible, Alleged or Confirmed Violation(s).

- The anticipated impact of the Mitigation Plan on the Bulk Power System reliability and an action plan to mitigate any increased risk to the reliability of the Bulk Power System while the Mitigation Plan is being implemented.

- A timetable for completion of the Mitigation Plan including the completion date by which the Mitigation Plan will be fully implemented and the Possible, Alleged or Confirmed Violation(s) corrected.

- Implementation milestones no more than three (3) months apart for Mitigation Plans with expected completion dates more than three (3) months from the date of submission. Additional violations could be determined for not completing work associated with accepted milestones.

- Any other information deemed necessary or appropriate.

The Mitigation Plan shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity.

6.3 Timetable for Completion of Mitigation Plans

The Mitigation Plan shall be completed in accordance with its terms. At the Compliance Enforcement Authority's discretion, the completion deadline may be extended for good cause

including, but not limited to: (i) operational issues such as the inability to schedule an outage to complete Mitigating Activities, and (ii) construction requirements in the Mitigation Plan that require longer to complete than originally anticipated. If the Mitigation Plan extends beyond the next applicable reporting/assessment period, sanctions for any violation of the applicable Reliability Standard(s) occurring during the implementation period will be held in abeyance and will be waived if the Mitigation Plan is satisfactorily completed.

Any violations assessed during the period of time the accepted Mitigation Plan is being implemented will be recorded by the Compliance Enforcement Authority with associated sanctions or Penalties. Regional Entities will report any findings of violations recorded during this time period to NERC with the notation that the Registered Entity is working under an accepted Mitigation Plan with an extended completion date with Penalties and sanctions held in abeyance until completion of the Mitigation Plan. Upon completion of the accepted Mitigation Plan in accordance with Section 6.6, the Compliance Enforcement Authority will notify the Registered Entity that any findings of violations of the applicable Reliability Standard during the period that the accepted Mitigation Plan was being implemented have been waived and no Penalties or sanctions will apply. Regional Entities will also notify NERC of any such waivers of violations of Reliability Standards.

A request for an extension of any milestone or the completion date of the accepted Mitigation Plan by a Registered Entity must be received by the Compliance Enforcement Authority at least five (5) business days before the original milestone or completion date. The Compliance Enforcement Authority may accept a request for an extension or modification of a Mitigation Plan if the Compliance Enforcement Authority determines the request is justified, and shall notify NERC of the extension or modification within five (5) business days.

If a Mitigation Plan submitted by a Registered Entity is rejected by the Regional Entity acting as Compliance Enforcement Authority or the Hearing Body in accordance with Section 6.5, the Registered Entity shall be subject to any findings of violation of the applicable Reliability Standards during the period the Mitigation Plan was under consideration and to imposition of any Penalties or sanctions imposed for such violations.

6.4 Submission of Mitigation Plans

A Mitigation Plan may be submitted at any time but shall have been submitted by the Registered Entity within thirty (30) days after being served the notification of Alleged Violation, if the Registered Entity does not contest the Alleged Violation and Penalty or sanction, or shall be reflected in a settlement agreement or Notice of Penalty. If the Registered Entity disputes the Alleged Violation or the Penalty or sanction, the Registered Entity shall submit its Mitigation Plan within ten (10) business days following issuance of the written decision of the Hearing Body, unless the Registered Entity elects to appeal the Hearing Body's determination to NERC. The Registered Entity may choose to submit a Mitigation Plan while it contests an Alleged Violation or Penalty or sanction or in response to a Notice of Possible Violation; such submission shall not be deemed an admission of a violation or the appropriateness of a Penalty or sanction. If the Registered Entity has not yet submitted a Mitigation Plan, or the Registered Entity submits a Mitigation Plan but it is rejected by the Regional Entity acting as Compliance Enforcement Authority or the Hearing Body in accordance with Section 6.5, any subsequent violations of the Reliability Standard identified by the Compliance Enforcement Authority

before the Hearing Body renders its decision will not be held in abeyance and will be considered as repeat violations of the Reliability Standard.

6.5 Review and Acceptance or Rejection of Proposed Mitigation Plans

Unless the time period is extended by the Compliance Enforcement Authority, it will complete its review of the Mitigation Plan, and will issue a written statement accepting or rejecting the Mitigation Plan, within thirty (30) days of receipt; otherwise the Mitigation Plan will be deemed accepted. In order to extend the initial or an extended period for review of the Mitigation Plan, the Compliance Enforcement Authority shall, within the initial or extended review period, notify the Registered Entity (and NERC if NERC is not the Compliance Enforcement Authority) that the review period is being extended and identify the date by which the Compliance Enforcement Authority will complete its review of the Mitigation Plan. The Compliance Enforcement Authority's extension notice shall also state that if the Compliance Enforcement Authority has not issued a notice by the end of the extended review period either stating that the Compliance Enforcement Authority accepts or rejects the proposed Mitigation Plan or further extending the Compliance Enforcement Authority's period for review of the Mitigation Plan, the Mitigation Plan will be deemed accepted.

If the Compliance Enforcement Authority rejects a Mitigation Plan, the Compliance Enforcement Authority will provide the Registered Entity with a written statement describing the reasons for the rejection, and will require the Registered Entity to submit a revised Mitigation Plan by the Required Date. The Compliance Enforcement Authority will notify the Registered Entity within ten (10) business days after receipt of a revised Mitigation Plan whether the Compliance Enforcement Authority will accept or reject the revised Mitigation Plan and provide a written statement describing the reasons for rejection and the Required Date for the second revised Mitigation Plan. If the second review results in rejection of the Mitigation Plan, the Registered Entity may request a hearing in accordance with the Hearing Procedures, by submitting to the Compliance Enforcement Authority a written request for hearing including an explanation of why the Mitigation Plan should be accepted. After the hearing is completed, the Compliance Enforcement Authority will issue a written statement accepting a Mitigation Plan it deems as appropriate.

Within five (5) business days after a Regional Entity accepts a Mitigation Plan, the Regional Entity (i) will notify NERC and the Registered Entity of the acceptance of the Mitigation Plan and (ii) will provide the accepted Mitigation Plan to NERC. NERC will review the accepted Mitigation Plan and, within thirty (30) days following its receipt of the Mitigation Plan from the Regional Entity, will notify the Regional Entity and the Registered Entity, on a contemporaneous basis, as to whether the Mitigation Plan is approved or disapproved by NERC. If NERC disapproves a Mitigation Plan that was accepted by the Regional Entity, NERC shall state its reasons for the rejection, and may state the changes to the Mitigation Plan that would result in approval by NERC. The Registered Entity shall not be subject to findings of violations of the specific Requirements of Reliability Standards that are the subject of the Mitigation Plan or to imposition of Penalties or sanctions for such violations with respect to the period of time the Mitigation Plan was under consideration by NERC and for a reasonable period following NERC's disapproval of the Mitigation Plan, so long as the Registered Entity promptly submits a modified Mitigation Plan that addresses the concerns identified by NERC.

If a Registered Entity submits a Mitigation Plan prior to issuance of a notification of Confirmed Violation or entry into a settlement, such as with a Self-Report or in response to a Notice of Possible Violation, the Regional Entity may provisionally accept the proposed Mitigation Plan. If the Regional Entity subsequently determines, upon completing its assessment of the Possible Violation, that the facts and circumstances are different than those on which the accepted Mitigation Plan was based, the Regional Entity may, by notice to the Registered Entity and to NERC, require the Registered Entity to submit a revised Mitigation Plan that fully addresses the facts and circumstances of the violation. The Regional Entity's notice shall state the additional or different facts and circumstances that need to be addressed in the revised Mitigation Plan. The Registered Entity shall submit a revised Mitigation Plan in response to the notice within thirty (30) days following the date of the notice, unless the Regional Entity specifies or allows a longer time period. The Registered Entity's revised Mitigation Plan shall be subject to review and acceptance or rejection by the Regional Entity and by NERC in accordance with this Section 6.5. If the Regional Entity issues a notification of Confirmed Violation or enters into a settlement with the Registered Entity and does not identify a need to request modifications to the provisionally-accepted Mitigation Plan based on additional or different facts and circumstances, the Regional Entity shall issue a notice to the Registered Entity, with a copy to NERC, stating that the "provisional" nature of the acceptance is terminated and the acceptance is final. The Regional Entity shall issue such notice within five (5) business days of issuance of the Notice of Confirmed Violation or entry into the settlement.

NERC will submit to FERC, as non-public information, an approved Mitigation Plan relating to violations of Reliability Standards within seven (7) business days after NERC approves the Mitigation Plan. NERC shall publicly post the approved Mitigation Plan as part of the public posting of the related Notice of Penalty in accordance with Section 8.0 or settlement in accordance with Section 5.6.

6.6 Completion/Confirmation of Implementation of Mitigation Plans

The Registered Entity shall provide updates at least quarterly to the Compliance Enforcement Authority on the progress of the Mitigation Plan. The Compliance Enforcement Authority will track the Mitigation Plan to completion and may conduct on-site visits and review status during Compliance Audit to monitor Mitigation Plan implementation.

Upon completion of the Mitigation Plan, the Registered Entity shall provide to the Compliance Enforcement Authority certification, signed by an officer, employee, attorney or other authorized representative of the Registered Entity, that all required actions described in the Mitigation Plan have been completed and shall include data or information sufficient for the Compliance Enforcement Authority to verify completion. The Compliance Enforcement Authority shall request such data or information and conduct follow-up assessments, on-site or other Spot Checks, or Compliance Audits as it deems necessary to verify that all required actions in the Mitigation Plan have been completed.

In the event all required actions in the Mitigation Plan are not completed within the applicable deadline including any extensions of the original deadline granted under Section 6.3, any violation(s) of a Reliability Standard subject to the Mitigation Plan that occurred during the originally scheduled time period for completion will be enforced immediately and a new Mitigation Plan must be submitted for acceptance by the Compliance Enforcement Authority. In

addition, the Compliance Enforcement Authority may conduct a Compliance Audit of, or issue a Remedial Action Directive to, the Registered Entity.

Upon request by NERC, the Regional Entity will provide to NERC the quarterly status reports and such other information as NERC requests. The Regional Entity will notify NERC when each Mitigation Plan is verified to have been completed.

6.7 Recordkeeping

The Compliance Enforcement Authority will maintain a record containing the following information for each Mitigation Plan:

- Name of Registered Entity.
- The date of the violation.
- Monitoring method by which the violation was detected, i.e., Self-Certification, Self-Report, Compliance Audit, Compliance Investigation, Complaint, etc.
- Date(s) of Notice of Possible Violation and notification of Alleged Violation (if applicable).
- Expected and actual completion date of the Mitigation Plan and major milestones.
- Expected and actual completion date for each required action.
- Accepted changes to milestones, completion dates, or scope of Mitigation Plan.
- Registered Entity's completion notice and data submitted as evidence of completion.

7.0 REMEDIAL ACTION DIRECTIVES

The Compliance Enforcement Authority may issue a Remedial Action Directive when such action is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat. A Remedial Action Directive may include, but is not limited to, any of the following: specifying operating or planning criteria, limits, or limitations; requiring specific system studies; defining operating practices or guidelines; requiring confirmation of data, practices, or procedures through inspection testing or other methods; requiring specific training for personnel; requiring development of specific operating plans; directing a Registered Entity to develop and comply with a plan to remediate a violation; imposing increased auditing or additional training requirements; and requiring a Registered Entity to cease an activity that may constitute a violation of a Reliability Standard.

A Remedial Action Directive may be issued to a Registered Entity at any time, including during any procedures relating to a Possible Violation or an Alleged Violation of a Reliability Standard. The Compliance Enforcement Authority will specify whether a Remedial Action Directive obviates the need for a Mitigation Plan.

Prior to issuing a Remedial Action Directive, the Compliance Enforcement Authority shall consult the Reliability Coordinator for the Registered Entity.

Any Remedial Action Directive must be provided in a notice to the Registered Entity and shall include: (i) a list of the Possible Violation(s) or Alleged Violation(s) of Reliability Standards that are the basis for issuance of the Remedial Action Directive; (ii) a discussion of the factual basis for the Remedial Action Directive; (iii) the requirements the Compliance Enforcement Authority is imposing to remove the imminent or actual threat to the reliability of the Bulk Power System; (iv) a deadline for compliance and a schedule for specific periodic updates to the Compliance Enforcement Authority; and (v) notice to the Registered Entity that failure to comply with the directive by the Required Date may result in further Remedial Action Directives or significantly increased sanctions.

The Compliance Enforcement Authority will cause the notice of the Remedial Action Directive to be delivered to the Registered Entity by (i) electronic mail to the Registered Entity's CEO or equivalent and copied to the Registered Entity's designated contact person for reliability matters and (ii) by a recognized express courier service that provides tracking and verification of delivery to the recipient. The notice will be deemed received on the earlier of the actual date of receipt of the electronic submission or receipt of the express courier delivery as specified by the express courier service's verification of delivery. The Compliance Enforcement Authority will monitor implementation of Remedial Action Directives as necessary to verify compliance.

The Compliance Enforcement Authority will notify NERC within two (2) business days after issuing a Remedial Action Directive and will copy NERC on all correspondence sent to the Registered Entity.

Once the Compliance Enforcement Authority has given the Registered Entity notice of the Remedial Action Directive, the Registered Entity may contest the Remedial Action Directive by giving written notice to the Compliance Enforcement Authority within two (2) business days following the date of actual receipt of notice of the Remedial Action Directive. Due to the urgency of resolving any objections to a Remedial Action Directive, the hearing shall be conducted under the expedited hearing process set forth in Section 1.9 of **Attachment 2, Hearing Procedures**. Notice to contest the Remedial Action Directive and participation in the hearing process set forth in Section 1.9 of **Attachment 2, Hearing Procedures** shall constitute the Registered Entity's right to appeal the Remedial Action Directive. The Registered Entity may elect not to implement the Remedial Action Directive until the hearing process is completed, or may proceed with implementing the Remedial Action Directive even if it is contesting the Remedial Action Directive.

8.0 REPORTING AND DISCLOSURE

8.1 Information to be Reported

Regional Entities shall promptly submit to NERC electronic reports containing current information concerning the information listed below. NERC will work with Regional Entities to specify form, content, timing, and method of submitting reports and notices.

(1) The status of the review and assessment of all Possible Violations, Alleged Violations and Confirmed Violations of Reliability Standards by Registered Entities,

(2) The potential impact of any Alleged Violation or Confirmed Violation on the reliability of the Bulk Power System,

(3) Sanctions and Penalties,

(4) Remedial Action Directives imposed,

(5) Mitigation Plans, and

(6) The name of a Regional Entity staff person knowledgeable about the information to serve as a point of contact.

8.2 Reporting to Applicable Governmental Authorities and Public Disclosure

Within two (2) business days of receiving a report from a Regional Entity of a Possible Violation, Alleged Violation, or Confirmed Violation, NERC shall notify FERC of the Possible Violation, Alleged Violation or Confirmed Violation.

Where the report pertains to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, NERC shall notify such other Applicable Governmental Authority, within two (2) business days of receiving a report of a Possible Violation, Alleged Violation or Confirmed Violation from the Regional Entity; provided, that NERC will not disclose any non-public U.S. compliance information that is subject to 18 C.F.R. §39.7(b)(4) to an Applicable Governmental Authority other than FERC without first obtaining permission from FERC for such disclosure and subject to any limitations placed by FERC on such disclosure. Likewise, NERC will not disclose non-public non-U.S. compliance information to an Applicable Governmental Authority (including FERC) without first obtaining permission from the Applicable Governmental Authority that has jurisdiction over the Registered Entity or portion of the Bulk Power System to which the non-public information pertains and subject to any limitations placed on such disclosure by such Applicable Governmental Authority or by other law of the applicable jurisdiction.

In any notice to, and request for permission to disclose compliance information from, FERC or another Applicable Governmental Authority pursuant to any provision of this Compliance Program, NERC will identify each Applicable Governmental Authority to which it proposes to disclose the information and the specific procedures that will be used for protecting from public disclosure any non-public compliance information that will be transferred to the other Applicable Governmental Authority or Authorities. The provisions of this paragraph do not apply to the provision by NERC to an Applicable Governmental Authority of information that is not directly related to a specific Registered Entity's compliance with a requirement of a Reliability Standard. NERC will publicly post on its website each Notice of Penalty, with any Critical Energy Infrastructure Information or other Confidential Information redacted (unless posting of the Critical Energy Infrastructure Information or Confidential Information has been determined to be permissible in accordance with Section 1500 of the Rules of Procedure), with the identity of the

violator, together with any statement submitted by the Registered Entity, when NERC files the Notice of Penalty with FERC pursuant to Section 5.9.

NERC will provide reports quarterly to FERC and, where a report contains information pertaining to a Registered Entity or to a portion of the Bulk Power System over which another Applicable Governmental Authority has jurisdiction, to such other Applicable Governmental Authority, on the status of all Possible, Alleged and Confirmed Violations for which mitigation activities have not been completed. All such reports to FERC and to other Applicable Governmental Authorities shall be provided in accordance with this Section.

9.0 DATA RETENTION AND CONFIDENTIALITY

9.1 Records Management

The Compliance Enforcement Authority records management policy shall provide for a routine and orderly process for the retention and disposal of electronic and paper records related to the Compliance Program, ensure verification of compliance with appropriate business, regulatory, and legal requirements and at a minimum conform to the data retention requirements of the Reliability Standards. The policy shall allow for the maintenance of records as required to implement the Compliance Program.

9.2 Retention Requirements

The Compliance Enforcement Authority records management policy will require that information and data generated or received pursuant to CMEP activities, including but not limited to, Self-Logging, Compliance Audits, Self-Certifications, Spot Checks, Compliance Investigations, Self-Reports, Periodic Data Submittals, Exception Reporting, and Complaints, as well as a hearing process, will be retained for the longer of (i) five (5) years or (ii) any retention period specified in a Reliability Standard or by FERC or another Applicable Governmental Authority. The obligation to retain information and data commences upon the initiation of the Compliance Program activity that produces the data or information. If the information or data is material to the resolution of a controversy, the retention period for such data shall not commence until after the controversy is resolved.

Upon request from NERC, Regional Entities will provide to NERC copies of such information and data. NERC will retain the information and data in order to maintain a record of activity under the Compliance Program. In providing the information and data to NERC, the Regional Entity shall preserve any mark of confidentiality.

9.3 Confidentiality and Critical Energy Infrastructure Information

9.3.1 Definitions

Information or data generated or received pursuant to Compliance Program activities, including a hearing process, shall be treated in a confidential manner pursuant to the provisions of Section 1500 of the NERC Rules of Procedure. The terms “Confidential Information,” “Confidential Business and Market Information,” “Critical Energy Infrastructure Information,” and “Critical Infrastructure” shall have the meanings stated in Appendix 2 to the NERC Rules of Procedure.

9.3.2 Protection of Confidential Information

The Compliance Enforcement Authority personnel (including any contractors, consultants and industry subject matter experts) and committee members, and participants in Compliance Program activities shall be informed of, and agree to comply with, Section 1500 of the NERC Rules of Procedure concerning Confidential Information.

9.3.3 Critical Energy Infrastructure Information

The Compliance Enforcement Authority will keep confidential all Critical Energy Infrastructure Information in accordance with Section 1500 of the NERC Rules of Procedures. Information deemed to be Critical Energy Infrastructure Information shall be redacted, in accordance with Section 1500 of the NERC Rules of Procedure, and shall not be released publicly.

ATTACHMENT 1

PROCESS FOR NON-SUBMITTAL OF REQUESTED DATA

FERC's regulations at 18 C.F.R §39.2(d) provide that each user, owner or operator of the Bulk Power System within the United States (other than Alaska and Hawaii) shall provide FERC, the ERO and the applicable Regional Entity such information as is necessary to implement section 215 of the Federal Power Act as determined by FERC and set out in the rules of the ERO and each Regional Entity. In order to enforce this requirement, if data, information, or other reports (including Mitigation Plans) requested from a Registered Entity in connection with a compliance monitoring process or enforcement process are not received by the Required Date, the Compliance Enforcement Authority may sequentially execute the following steps for each Reliability Standard Requirement for which the Compliance Enforcement Authority has requested data, information, or other reports. However, upon a request from the Registered Entity submitted prior to the Required Date stating in reasonable detail the basis for the Registered Entity's need for additional time, the Compliance Enforcement Authority may afford the Registered Entity reasonable additional time to submit the data, information or report due to the scope or difficulty of the request or requirement for data, information or reports, the amount of the data, information or reports requested or required, or the form in which the data, information, or other reports has been requested or is required to be provided.

Step 1: The Compliance Enforcement Authority will issue a notification to the Registered Entity's designated contact for reliability matters, identifying the data, information or report that were requested or required and the Required Date and stating that the Required Date has passed and the Registered Entity should, within five (5) business days, either provide the data, information or report, or contact the Compliance Enforcement Authority with a proposed date by which the Registered Entity will provide the data, information or report. If the Compliance Enforcement Authority agrees with the Registered Entity on a revised date by which the Registered Entity will provide the data, information or report, the agreed revised date shall become the Revised Required Date.

Step2: If the Registered Entity does not provide a response to the notification in, and in accordance with, Step 1, within five (5) business days, or by a revised date as agreed to in Step 1, the Compliance Enforcement Authority will issue a notification to the Registered Entity's designated contact for reliability matters, with a copy to the Registered Entity's chief executive officer or equivalent, stating that if the data, information or report is not received within ten (10) business days, the Compliance Enforcement Authority may (i) implement a compliance monitoring process directed to the Registered Entity, or (ii) issue a Notice or other notification of Alleged Violation and Proposed Penalty or Sanction at the Severe Violation Severity Level to the Registered Entity for the Reliability Standard Requirement to which the requested or required

data, information or report relates.

Step 3: If the Registered Entity fails to produce the requested or required data, information or report in response to the notification in Step 2 within the ten (10) business day cure period set forth in the Step 2 notification, the Compliance Enforcement Authority may take any action of which the Registered Entity was notified in the Step 2 notification, including issuing a Notice or other notification of Alleged Violation and Proposed Penalty or Sanctionat the Severe Violation Severity Level for the Reliability Standard Requirement to which the requested or required data, information or report relates.

The process described in this Attachment 1 is intended to be applied where a Registered Entity does not respond by the Required Date to an initial request for data, information or reports in connection with a compliance monitoring and enforcement process and does not respond to subsequent requests (Steps 1 and 2 above) by the stated deadline. This process is not intended to apply where the Registered Entity responds, prior to the Required Date, to the initial request or requirement for data, information or reports with requests for clarification, definition of scope, or similar questions concerning the request or requirement for data, information or reports, or requests, prior to the Required Date, additional time to respond based on the scope or difficulty of the request or requirement for data, information or reports, the amount or extent of the data, information or reports requested or required, or the form in which the data, information or report is to be provided, and works with the Compliance Enforcement Authority in good faith to respond to the request or requirement for data, information or reports, as modified if appropriate by the Compliance Enforcement Authority based on questions raised by the Registered Entity.

ATTACHMENT 2 - HEARING PROCEDURES

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ATTACHMENT 2 - HEARING PROCEDURES

1.1 Applicability, Definitions and Interpretation

1.1.1 Procedure Governed

(a) The provisions set forth in this **Attachment 2** ("Hearing Procedures") shall apply to and govern practice and procedure before the Compliance Enforcement Authority in hearings in the United States conducted into:

(1) whether Registered Entities within the Compliance Enforcement Authority's Area of Responsibility have violated Reliability Standards, and

(2) if so, to determine the appropriate Mitigation Plans 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. Section 39.7(g)(2).

(b) Any hearing conducted pursuant to these Hearing Procedures shall be conducted before a Hearing Officer and a Hearing Body ~~established by the Compliance Enforcement Authority~~. Where the Hearing Body established under Rules of Procedure Section 403.15A is comprised, in whole or in part, of industry stakeholders, the composition of the Hearing Body, after any recusals or disqualifications, shall be such that no two industry segments may control, and no single industry segment may veto, any decision by the Hearing Body on any matter brought before it for decision. Where the Hearing Body established under Rules of Procedure Section 403.15A is comprised solely of independent members and an independent hearing Officer, decisions shall require a majority vote. For the Hearing Body established under Rules of Procedure Section 403.15B, decisions shall require a majority vote.

(c) 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 requiring compliance with a Remedial Action Directive.

(d) If a final order has been entered by the Hearing Body, or the Hearing Body has issued a ruling determining that there are no issues to be decided regarding the Alleged Violation, proposed Penalty amount, proposed Mitigation Plan or proposed Remedial Action Directive, or the Registered Entity and the Compliance Enforcement Authority have entered into a settlement agreement resolving the matters that are the subject of the hearing, the hearing shall be terminated by the Hearing Body and no further proceedings shall be conducted before the Hearing Body.

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 Body, for good cause shown, either

upon the Hearing Officer's or the Hearing Body's own motion or upon the motion of any Participant.

1.1.3 Standards for Discretion

The Compliance Enforcement Authority'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 Compliance Enforcement Authority 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 the Compliance Enforcement Authority's conflict of interest policy.

(e) Impartiality - Persons appearing before the Hearing Body 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) Any ruling, order or decision of the Hearing Officer referenced in these Hearing Procedures shall be made by the Hearing Body where the composition of the Hearing Body consists of independent members and an independent Hearing Officer.~~

(~~c~~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.

(~~d~~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~~ [Intentionally Left Blank]

~~Unless otherwise defined, as used in these Hearing Procedures, definitions in Appendix 2 of the NERC Rules of Procedure shall apply. For ease of reference, the following defined terms used in these Hearing Procedures are also set forth below:~~

~~"Clerk" shall mean an individual assigned by the Compliance Enforcement Authority to perform administrative tasks relating to the conduct of hearings as described in these Hearing Procedures.~~

~~"Compliance Enforcement Authority's Area of Responsibility" means the Compliance Enforcement Authority's Region. If a Regional Entity is the Compliance Enforcement Authority, the Compliance Enforcement Authority's Area of Responsibility is shown in Exhibit A to the delegation agreement between the Regional Entity and NERC.~~

~~"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 act 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.~~

~~"Director of Compliance" means the Director of Compliance of NERC or of the Compliance Enforcement Authority, as applicable, or other individual designated by the Compliance Enforcement Authority, who is responsible for the management and supervision of Compliance 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.~~

~~"ERO" or "Electric Reliability Organization" 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 in the United States, subject~~

to Commission review. The organization may also have received recognition by Applicable Governmental Authorities in Canada and Mexico to establish and enforce Reliability Standards for the Bulk Power Systems of the respective countries.

"Evidentiary Hearing" means a hearing at which one or more Participants submits evidence for the record. A Testimonial Hearing is an Evidentiary Hearing, but an Evidentiary Hearing does not necessarily include the presentation of testimony by witnesses in person.

"FERC" means the Federal Energy Regulatory Commission.

"Hearing Body" means the body established or designated by the Compliance Enforcement Authority to conduct hearings and issue decisions concerning disputed compliance matters in accordance with these Hearing Procedures.

"Hearing Officer" means an individual employed or contracted by the Compliance Enforcement Authority and designated by the Compliance Enforcement Authority to preside over hearings conducted pursuant to these Hearing Procedures.

"Participant" means a Respondent and any other Person who is allowed or required by the Hearing Body 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 Compliance Staff of the Compliance Enforcement Authority that participate in a proceeding.

"Penalty" means and 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 Registered Entity or 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 Registered Entity's or Respondent's violation and take into consideration any timely efforts made by the Registered Entity or 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.

"Respondent" means the Registered 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 or the Compliance Enforcement Authority who have the authority to make initial determinations of compliance or violation with Reliability Standards by Registered Entities and associated Penalties and Mitigation Plans.

"Technical Advisor" means any Staff member, third-party contractor, or industry stakeholder who satisfies the Compliance Enforcement Authority'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 Body.~~

~~"Testimonial Hearing" means an Evidentiary Hearing at which the witness or witnesses on behalf of one or more Participants appears in person to present testimony and be subject to cross-examination.~~

1.2 General Provisions including Filing, Service, Transcription and Participation

1.2.1 Contents of Filings

All filings made with the Hearing Body 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 made to a Hearing Body established under Rules of Procedure Section 403.15A (Regional Entity Hearing Process) or 4013.15B (Consolidated Hearing Process) shall be made with the Clerk ~~of the Compliance Enforcement Authority located at its principal office~~. The Clerk's office will be open during the ~~Compliance Enforcement Authority's~~ regular business hours of the Compliance Enforcement Authority or NERC, each day except Saturday, Sunday, legal holidays and any other day declared by the Compliance Enforcement Authority or 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 Body. Filings will be considered made when they are date stamped received by the Clerk. To be timely, filings must be received no later 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. ~~by the Compliance Enforcement Authority.~~

(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 Body 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.

(f) Verification

The facts alleged in a filing need not be verified unless required by these Hearing Procedures, the Hearing Officer or the Hearing Body. 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, Director of Enforcement~~Compliance~~ and the Registered Entity's compliance contact as registered with the Compliance Enforcement Authority, 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, 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 Body upon the members of the Hearing Body and each individual whose name is on the service list for the proceeding. Service may be made by personal delivery, email, 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. The Clerk shall transmit a copy of the record of a proceeding to NERC~~the ERO~~ at the time that the Compliance Enforcement Authority transmits ~~to the ERO~~ either (1) a Notice of Penalty, or (2) a Hearing Body 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 Compliance Enforcement Authority or NERC 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 Compliance Enforcement Authority 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 Body 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 Body 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 Body 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 Compliance Enforcement Authority or NERC 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 Body 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 Body. All notices of hearings shall set forth the date, time and place of hearing.

1.2.10 Location of Hearings and Conferences

Except as provided below, a~~A~~ll hearings and oral arguments shall be held at the principal office of the Compliance Enforcement Authority unless the Hearing Officer or Hearing Body designates a different location.

If the Compliance Enforcement Authority has adopted the Consolidated Hearing Process under Rules of Procedure Section 403.15B, all hearings and oral arguments shall be held at the principal office of the Compliance Enforcement Authority unless NERC, the Compliance Enforcement Authority, and the Registered Entity agree to 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 Body, 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 Body or by FERC, no other Persons shall be permitted to intervene or otherwise become a Participant to the proceeding.

(b) The Hearing Body may allow a Person to intervene only if the Hearing Body determines that the Person seeking intervention has a direct and substantial interest in the outcome of the Alleged Violation, proposed Penalty or sanction, Mitigation Plan, or Remedial Action Directive that is the subject of the proceeding. Examples of a direct and substantial interest in the outcome shall include

(1) that the Person seeking intervention 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) that the Person seeking intervention 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 Body 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 time period, not to exceed seven (7) 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 Body as to whether or not the motion to intervene should be granted.

(e) The Hearing Body 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 Body 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 Body and the motion to intervene shall be deemed granted or denied by the Hearing Body 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 Body, 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 Body, 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 allowed to intervene and become a Participant to a proceeding is required to take the record and the procedural status of the proceeding as it stands on the date the Person's motion to intervene is granted by the Hearing Body.

(i) A Person may appeal a decision of the Hearing Body denying the Person's motion to intervene, and the Compliance 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 ~~d~~Director of ~~e~~Enforcement no later than seven (7) days following the date of the decision of the Hearing Body granting or denying the motion to intervene.

1.2.13 Proceedings Closed to the Public

No hearing, oral argument or meeting of the Hearing Body shall be open to the public, and no notice, ruling, order or any other issuance of the Hearing Officer or Hearing Body, 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) determine that public release is appropriate. Only the members of the Hearing Body, 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 by the Compliance Enforcement Authorities, 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 Body 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:

(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 Compliance Enforcement Authority, including without limitation its members, board of directors or trustees, compliance committee, any other committees or subcommittees, Staff, contracted employees, Hearing Body 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 Compliance Enforcement Authority 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 Compliance Staff submits to the Registered Entity a statement rejecting the Registered Entity's proposed revised Mitigation Plan submitted after Compliance Staff rejected the Registered Entity's initial proposed Mitigation Plan.

(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 Compliance Staff submits to the Registered Entity its statement identifying a disagreement with the Registered Entity's proposed Mitigation Plan, whichever is applicable.

(c) If the Registered Entity does not file a hearing request within the time 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 Compliance Staff's rejection of the revised Mitigation Plan, whichever is applicable.

(d) In accordance with Section 5.3 of the Compliance Program, a Notice of Alleged Violation issued to a Registered Entity or a Staff statement setting forth its rejection of a Registered Entity's proposed revised Mitigation Plan shall clearly state that the Registered Entity has the option to contest the Alleged Violation, proposed Penalty, or both, or the Compliance Staff's rejection of the proposed revised Mitigation Plan, 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 should be approved;

(2) state the relief that the Registered Entity requests the Hearing Body 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 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, Compliance 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 a 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 and the Compliance Staff's statement rejecting the proposed revised Mitigation Plan.

(h) If the Compliance Enforcement Authority has adopted the Consolidated Hearing Process, the Compliance Staff must forward a hearing request to NERC within three (3) business days of receiving the request.

1.3.2 Compliance Staff's Response to Request for Hearing

(a) If the Registered Entity's request for hearing requests that the shortened hearing procedure be used, the Compliance Staff shall file a response stating whether it agrees to the use of the shortened hearing procedure.

(b) If the Registered Entity's request for hearing requests that the Registered Entity's proposed revised Mitigation Plan should be approved, the Compliance Staff shall file a response stating the Compliance Staff's position as to why the Registered Entity's proposed revised Mitigation Plan should not be approved and setting forth any additional terms that the Compliance Staff believes should be included in the Mitigation Plan.

(c) If the Registered Entity's request for hearing does not request that the shortened hearing procedure be used and does not request that the Registered Entity's proposed revised Mitigation Plan should be approved, the Compliance Staff may, but is not required to, file a response stating, as applicable, the basis for the Compliance 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 Compliance 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 Body 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 Body shall utilize a Hearing Officer to preside over the shortened hearing procedure in accordance with Section 1.4.2. But, 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 argument;

(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 argument, which comment 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 pursuant to subsection (d), 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 Body shall ~~strive, but is not required, to~~ issue a final order within one hundred twenty (120) days of the notice of hearing. The Hearing Body may extend this deadline for good cause and shall provide written notice of any extension to all Participants.

The Hearing Officer or Hearing Body may modify any time period set forth within this Paragraph as warranted by the circumstances but it will be the objective of the Hearing Body 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 Compliance Enforcement Authority shall utilize a~~A Hearing Officer shall~~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 Body as set forth in Section 1.4.3. Members of the Hearing Body 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 Body for final decision through the presentation to the Hearing Body 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.

(c) The Hearing Officer~~Compliance Enforcement Authority~~ 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 Body

(a) The composition of the Hearing Body, after any recusals or disqualifications, shall be such that no two industry segments may control, and no single industry segment may veto, any decision of the Hearing Body on any matter brought before it for decision.

(b) The Hearing Body 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 Body 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 Body may request of, and shall receive from, the Clerk, a copy of any filing by a Participant. The Hearing Body 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 Body.

(3) The Hearing Body 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 Body, any member of the Hearing Body may ask questions directly of any Participant or witness.

(4) The Hearing Body 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 Body 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 Body 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.

(6) The Hearing Body shall resolve the issue(s) in every hearing through the issuance of a final order. In issuing a final order, the Hearing Body 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.

(7) If the Compliance Enforcement Authority has adopted the Consolidated Hearing Process under Rules of Procedure Section 403.15B, the Hearing Officer will cast the deciding vote in the event any Hearing Body vote results in a tie.

1.4.4 Interlocutory Review

(a) A Participant shall be allowed to seek interlocutory review by the Hearing Body 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 Body, 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 Body 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 Body.

(d) On review of a Hearing Officer's ruling, the Hearing Body 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 Body 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 Body, and (ii) majority vote of the members of the Hearing Body voting on the final order (which number of members voting shall not be less than a quorum). Petitions to rehear or reconsider the Hearing Body'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 Body 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 Body 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 Body shall recuse himself or herself from a proceeding if participation would violate the ~~Compliance Enforcement Authority's~~ applicable conflict of interest policy of the Compliance Enforcement Authority, and/or that of NERC under the Consolidated Hearing Process.

(b) Any Participant may file a motion to disqualify or for recusal of a Hearing Officer, Technical Advisor or member of the Hearing Body 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 Body's consideration upon the filing of a motion for disqualification unless the Hearing Officer is the subject of the motion. The Hearing Body, 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 Body 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 Body does not remain after any recusals and rulings on motions for disqualification, then the Compliance Enforcement Authority, or NERC under the Consolidated Hearing Process, shall appoint at least the number of new members to the Hearing Body necessary to create a quorum. The new member(s) shall serve on the Hearing Body through the conclusion of the proceeding but not thereafter. Any new member of the Hearing Body shall be subject to the provisions applicable herein to all Hearing Body members.

1.4.6 Technical Advisor

(a) The Hearing Officer and/or the Hearing Body 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, determination of a Possible Violation, Alleged Violation or Penalty, or assessment of a Registered Entity's proposed Mitigation Plan 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 Body uses a Technical Advisor to assist in any hearing, the Hearing Officer or Hearing Body 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 Body, 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 Body, 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:

(A) in writing if the writing is simultaneously provided to all Participants; or

(B) orally if a representative for every Participant is present in person or by telephone;

(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) Exceptions

(1) The proscription in subsection (a)(1) does not prohibit members of the Compliance Staff from communicating with the 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) The proscription in subsection (a)(1) does not prohibit communications between or among members of the Hearing Body, 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 Body 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 Body and representatives of the Compliance Enforcement Authority for purposes of establishing the hearing forum, or between NERC, the Regional Entity, and the Registered Entity for purposes of establishing the hearing forum under the Consolidated Hearing Process.

(c) Any member of the Hearing Body, 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.

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. All representatives appearing before the Hearing Body 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 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 Body 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 or Mitigation Plans, arising out of the same event or occurrence. Such consolidation may be allowed in the discretion of the Hearing Officer or Hearing Body, as applicable.

1.5 Prehearing Procedure

1.5.1 [Intentionally left blank]

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, for the following purposes:

(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 Body 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 Body.

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 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 Body, 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 of record shall be supported by affidavit.

(b) Unless otherwise specified by the Hearing Officer or Hearing Body, 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 Body may deny dilatory, repetitive, or frivolous motions without awaiting a response. Unless otherwise ordered by a Hearing Officer or Hearing Body, 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:

(A) requests for information to the Respondent;

(B) every written request, including e-mail, directed to persons not employed by the Compliance Enforcement Authority to provide information or Documents or to be interviewed;

(C) the Documents provided in response to any such requests described in (A) and (B) above;

(D) all transcripts of testimony recorded during the Staff investigation and all exhibits to the transcript;

(E) all other Documents obtained from the Respondent; and

(F) all other Documents obtained from persons not employed by the Compliance Enforcement Authority.

The sole grounds on which Staff is authorized to withhold Documents from inspection and copying are the bases set forth in subsection 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 Remedial Action Directive.

(2) Where there are Participants in a proceeding in addition to a single Respondent and Compliance Staff, the Hearing Officer or Hearing Body 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 Compliance Enforcement Authority 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:

(A) the Document is privileged to the Compliance Enforcement Authority or NERC, or constitutes attorney work product of counsel for the Compliance Enforcement Authority or NERC (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);

(B) 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;

(C) the Document would disclose

(i) an examination, investigatory or enforcement technique or guideline not otherwise made public of the Compliance Enforcement Authority, a federal, state, or foreign regulatory authority, or a self-regulatory organization;

(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; 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 Compliance Enforcement Authority, a federal, state, or foreign regulatory authority, or a self-regulatory organization; or

(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 subsections (A), (B), (C) or (D) that is capable of being redacted, Staff shall make the Document available for inspection and copying by the other Participants in redacted form.

(2) Nothing in subsections (b)(1)(B), (C) or (D) authorizes Staff to withhold a Document, or a part thereof, that contains exculpatory evidence. Nothing in subsection (b)(1) requires Staff to withhold a Document from disclosure.

(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 subsection (b)(1), 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 time 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 Compliance Enforcement Authority 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 Compliance Enforcement Authority's offices during normal business hours. A Participant shall not be given custody of the Documents or be permitted to remove the Documents from the Compliance

Enforcement Authority's offices, other than copies of Documents made available by the Compliance Enforcement Authority 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 Compliance Enforcement Authority.

(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 Body 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 Body upon motion by a Participant, or by the Hearing Officer, or by the Hearing Body 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 Body 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 Body 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 Body,

(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 Body.

(6) Unless otherwise ordered by the Hearing Officer or Hearing Body, 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 Body shall determine whether the failure to make the Document available was harmless error.

(9) Unless otherwise ordered by the Hearing Officer or Hearing Body, 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;

(2) the exercise of due diligence in the conduct of discovery by a Participant; and

(3) 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.

(b) 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.

(c) 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 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.

(d) 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 surrebuttal case that responds to the Registered Entity's rebuttal case.

(e) 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.

(f) 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.

(g) 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;

(ii) Critical Energy Infrastructure Information;

(iii) information related to a Cyber Security Incident;

(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 Staff, any Compliance Enforcement Authority, 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 Body 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 Body.

(b) The purpose of such memoranda will be to aid the Hearing Officer and Hearing Body 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 Body that it certify, or the Hearing Body 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 Body, on its own motion, wishes to present a question to the Hearing Body 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 Body. If the request for certification is based on the motion of a Participant, the Hearing Officer shall also submit to the Hearing Body 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 Body 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 Body 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 Body 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 Body determines that the proposed question should be certified to the Board of Trustees Compliance Committee, the Hearing Body 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 Body.

(f) 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 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 Body. Any Participant's request for such statements, or a Hearing Officer or Hearing Body 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 Body 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) Compliance 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.

(d) 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 Body, 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.

(e) 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 Compliance Enforcement Authority'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 Compliance Enforcement Authorities.

(2) The orders, transcripts, exhibits, pleadings or any other matter contained in the record of other docketed proceedings of the Compliance Enforcement Authority.

(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 Compliance Enforcement Authority.

(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 Body 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 Body. Any redirect examination shall be limited in scope to the witness' cross-examination and questions of the Hearing Officer and members of the Hearing Body.

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 Body'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 Body'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 Remedial Action Directive that the Hearing Officer proposes the Hearing Body 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 Body 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 Body. The Hearing Body 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 Body'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 Body'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.

1.7.8 Hearing Body Final Order

(a) Following the receipt of the initial opinion, any exceptions and replies thereto, and oral argument, if any, the Hearing Body shall issue its final order.

(b) Issuance of a final order shall require (i) a quorum of the Hearing Body, 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 Body, and (ii) majority vote of the members of the Hearing Body voting on the final order (which number of members voting shall not be less than a quorum).

(c) The Hearing Body ~~shall strive, but~~ shall ~~not be required, to~~ issue its final order within thirty (30) days following the last to occur of the initial opinion, exceptions or replies thereto, or oral argument. The Hearing Body 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 Body 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 or Mitigation Plan 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

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 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 Body;

(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 Body'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 Body 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 Compliance Enforcement Authority, may appeal a final order of the Hearing Body to NERC in accordance with Rule 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 Compliance Enforcement Authority's settlement procedures, provided, that (i) the Compliance Enforcement Authority may decline to engage in or continue settlement negotiations after a Possible Violation or Alleged Violation becomes a Confirmed Violation, and (ii) the Compliance Enforcement Authority, 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. The Compliance Enforcement Authority will notify NERC within two (2) business days after its Staff issues a Remedial Action Directive.

(b) The Registered Entity may contest the Remedial Action Directive by filing a written notice with ~~the Clerk of~~ the Compliance Enforcement Authority 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 to the Compliance Enforcement Authority within the required time period, the Registered Entity shall be deemed to have waived its right to contest the Remedial Action Directive.

(c) If the Compliance Enforcement Authority has adopted the Consolidated Hearing Process under Rules of Procedure Section 403.15B, it must forward a request for a Remedial Action Directive hearing to NERC within one (1) business day of receiving the request.

(d~~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 1.9.2. 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 Body 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 Body. Oral argument shall not be held.

(c) The Hearing Body 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 Body 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 Body shall issue a full written decision. The written decision shall state the conclusions of the Hearing Body with respect to the Remedial Action Directive, and shall explain the reasons for the Hearing Body's conclusions.